INTERMOUNTAIN POWER SERVICE CORPORATION

DCS Replacement Project

Master Plan

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EXECUTIVE SUMMARY

Introduction:
The DCS Replacement Project Working Group was assigned to review the status of existing control and process systems at the Intermountain Generating Station (IGS) and develop recommendations to ensure the long term viability of the process control and information system functions. The findings of this review are summarized in this document. This document has been updated to reflect subsequent modifications to the IGS DCS Replacement Project Master Plan.

Overview:
Replacement of the IGS unit control and data acquisition systems following a phased replacement plan is recommended.

Unit controls including the Coordinated Control Systems(CCS), Turbine Control Systems (TCS), Burner Control Systems (BCS), and Boiler Feed Pump Turbine Control Systems (MDT-20) are recommended for replacement prior to the NOx modifications, which will be required by December 31, 2007. This is based on the requirements for additional control software and hardware capability necessary to complete the emission reduction project.

Installation of a Simulator is recommended to support operator training and controls logic validation. Simulator installation must be completed 12 to 18 months prior to the control system implementation.

Replacement of the FOX 1/A data acquisition system (DAS) and Rochester Sequence Of Events Recorder (SOE) is recommended to be completed prior to the replacement of the control systems. This will address problems with decreasing system reliability and failures and concerns on long-term support with the DAS. Concurrent replacement of the SOE with the DAS is recommended to minimize project cost and mitigate project risk.

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DCS SYSTEMS STATUS and FUTURE

General

The DCS Replacement Project Working Group was assigned to review the status of existing control and process data systems at the Intermountain Generating Station (IGS) and develop recommendations to ensure the long term viability of control system functions. The findings of this review are found in this document. This section includes a status summary and general recommendations for DCS systems.

Included Systems

1. **Process Data Systems**
   a. FOX 1/A computer systems
   b. Plant Data Systems: PI Plant Information Systems
2. **Process Control Systems**
   a. Foxboro Videospec and Microspec systems
   b. GE Turbine Automatic Controls (TAC), Turbine-Generator Supervisory Instrumenation (TGSI), Electro-Hydraulic Control (EHC), and the MDT20 BFPT Control systems
   c. Rochester Information System(RIS) - *sequence of events (SOE) recorder*
   d. Bailey burner control systems (BCS).
3. **IGS Controls Simulator** - Training and Controls Testing System

Status & Condition

The primary concerns facing the plant process data and control systems are issues of obsolescence and lack of expansion capacity.

The FOX 1/A systems are experiencing increasing levels of failure and difficulty in obtaining replacement components. While the impact of these failures has been minimized to date, system trends are towards increased rates of failure and is likely to have an increased impact on unit operation.

The PI system uses newer technology. Obsolescence and spare parts availability are not currently problems, but there is some indication of upcoming issues in these areas on the primary server, PI-Home. Long range plans are in place to meet those concerns through the PI Migration Project. Investigation was made into the possibility of consolidation of PI functions into a future DCS system. However, current DCS systems do not adequately provide the historian and analysis capabilities of PI and, in fact, some utilize PI as the basis of their long term data archival offering. Continuation of PI as a separate, plant wide system is recommended.

The Foxboro, Bailey, and Rochester control systems are still operating reliably. Some problems with spare parts availability have been encountered and solved. However, these systems are the same generation of equipment as the FOX 1/A systems, and it is expected that the problems currently experienced on the FOX 1/A systems are a precursor to the future on the control systems.

The General Electric (GE) turbine controls systems are currently experiencing failure and reliability problems with TAC systems most affected. Increasing failure and reliability problems are expected on these systems.

IGS currently has no simulator system for training or controls testing.

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Proposed Replacement Sequence & Schedule

It is proposed that a four (4) phase, multi-year capital project be initiated to replace the IGS process data and control systems. The recommended sequence and schedule are provided below.

1. **Data Acquisition Systems: FOX 1/A Systems and Sequence of Events Recorders**
   FOX 1/A and Rochester SOE replacement is recommended for Phase 1 and Phase 2 of the project beginning with Unit 2 in 2003-04 and concluding with Unit 1 in 2004-05. The basis for this recommendation is as follows:
   a. FOX 1/A systems reliability is a critical concern. These systems stand the greatest risk of failure and suffer from increasing failure rates. Delay of FOX 1/A replacement will likely reduce availability of alarming, AGC control, permissive screens, and process graphics in the control room.
   b. Outage window constraints will not allow complete DCS replacement on a unit during a single outage. Replacement of both data portions of the DCS (SOE and FOX 1/A) is recommended for phases 1 and 2 to balance installation burden between project phases.
   c. FOX 1/A and SOE replacement prior to the controls will allow operations personnel to gain experience on the DCS hardware prior to being required to use the same type of hardware for unit control.
   d. The phased replacement of the DCS systems will reduce dependence on contractor labor, minimize risk to unit availability, and lower the overall project cost.

2. **Simulator**
   The installation of a simulator is recommended to begin in 2003-04 with completion no later than 2004-05. Completion of a simulator is required eight (12) to twelve (18) months prior to the controls in order to realize the full benefits. The benefits of a simulator are as follows:
   a. Controls can be developed and tested prior to installation of the control systems. This will minimize the post-outage start-up time.
   b. Operations personnel can be trained in advance on the new controls to ensure high availability with the new systems.
   c. Operational equipment scenarios with alternative controls solutions can be tested by Operations and Engineering.
   d. Other appropriate support personnel can be trained in advance.

3. **Controls: CCS, Turbine, BFPT, and Burner Management Controls; Flame Scanners; and, Overall Systems Optimization**
   Replacement of the controls is recommended for Phase 3 and Phase 4 of the project. Unit 2 controls replacement installation is envisioned for 2005-06 with Unit 1 replacement following in 2006-07. Replacement is essential for the following reasons:
   a. The current systems are at capacity. New controls hardware will be required for the NOx reduction project.
   b. The existing systems are becoming obsolete. Unacceptable levels of reliability and availability are expected.

Deferral of the FOX 1/A replacement is possible but not recommended for reasons explained in greater length in subsequent sections of this document. The installation of a simulator and new controls systems cannot be deferred beyond the recommendations of this report, however acceleration of these phases is possible if warranted. A recommended schedule is found on page 3.

RECOMMENDED DCS REPLACEMENT TIMELINE

Calendar Year	* Denotes Approximate Date of Annual Major Outage 2000 Jul, 2001 Jan *	Jul, 2002 Jan *	Jul, 2003 Jan *	Jul, 2004 Jan *	Jul, 2005 Jan *	Jul, 2006 Jan *	Jul, 2007 Jan *	Jul, 2008 Jan *
Budget Year	FY2000-2001	FY2001-2002	FY2002-2003	FY2003-2004	FY2004-2005	FY2005-2006	FY2006-2007	FY2007-2008
DAS and SOE Replacement Schedule	Technology investigation	Continue technology investigation, complete preliminary engineering, identify qualified bidder , budget, and develop preliminary specifications, issue RFP, Select Vendor.	Complete preliminary engineering, budget, and develop project specifications, issue RFP, Select Vendor.	Purchase and Install U2 DAS and SOE replacement systems.	Purchase and Install U1 DAS and SOE replacement systems.			12/31/07 New NOx Requirements on 12/31/2007 Replacement must be completed prior to NOx deadline.
Simulator Replacement Schedule			Budget for simulator, complete preliminary engineering, budget, and develop project specifications, issue RFP, Select Vendor.	Purchase simulator, develop simulator model, begin controls integration with simulator.	Complete controls integration and testing on simulator Begin Opr. Trai n-ing	Operator Training		
CCS, TCS, BCS and BFPT Controls Replacement Schedule		Operator Training	Complete controls integration and testing on simulator and begin training.	Controls Software Development Initiated	Budget for CCS, TCS, BCS and BFPT controls replacement systems.	Purchase and Install U2 CCS, TCS, BCS and BFPT controls replacement systems..	Purchase and Install U1 CCS, TCS, BCS and BFPT controls replacement systems.	

OVERVIEW of RECOMMENDED SCHEDULE

Year 1: Fiscal Year 2001-02

1. Complete preliminary system engineering.
2. Initiate update of DCS documentation.
3. Complete investigation and define preferred technology for DCS replacement systems.
4. Identify qualified vendors.

Year 2: Fiscal Year 2002-03

1. Develop specifications for replacement DCS and Simulator Systems.
2. Submit specifications with requests for proposals to DCS and Simulator vendors.
3. Evaluate proposals and select DCS and Simulator vendors.
4. Complete documentation of DCS systems and databases.
5. Begin development of Simulator.

Year 3: Fiscal Year 2003-04

1. Purchase and install Unit 2 DAS and SOE systems.
    a. Build and configure DAS and SOE systems.
    b. Receive, stage, and pre-test Unit 2 systems.
    c. Train DAS and SOE system users and support personnel on tested system.
    d. Remove old system and complete full installation during the four (4) week U2 outage.
2. Purchase Simulator and begin development
    a. Initiate DCS vendor development of DCS controls software and logic.
    b. Receive, stage, and test simulator hardware at Simulator vendor site.
    c. Develop simulator model.
    d. Receive controls software from DCS vendor and begin DCS integration with Simulator.

Year 4: Fiscal Year 2004-05

1. Purchase and install Unit 1 DAS and SOE systems.
    a. Build and configure DAS and SOE systems.
    b. Receive, stage, and pre-test the Unit 1 systems.
    c. Complete training for support personnel and system users on tested system.
    d. Remove old system and complete full installation during four (4) week U1 outage.
2. Simulator Development and Implementation
    a. Complete Simulator development and testing of simulated unit models.
    b. Build DCS controls displays.
    c. Complete controls integration and check-out on Simulator
    d. Complete system FAT and SAT testing for simulator.
    e. Begin operator training.

Year 5: Fiscal Year 2005-06

1. Continue operator training on Simulator.
2. Purchase and install controls portion (CCS, TCS, BCS, and BFPT Controls) of DCS system for Unit 2.
    a. Finalize development of DCS controls interfaces and displays.
    b. Receive, stage, and pre-test the Unit 2 DCS system.
    c. Remove old system and complete DCS installation during four (4) week Unit 2 outage.
    d. Remove main control panel and replace with DCS command center on Unit 2.

Year 6: Fiscal Year 2006-07

1. Continue operator training on Simulator.
2. Purchase and install controls portion of DCS system for Unit 1.
    a. Receive, stage, and pre-test the U1 DCS system.
    b. Remove old system and complete DCS installation during four (4) week Unit 1 outage.
    c. Remove main control panel and replace with DCS command center on Unit 1.
    d. Replace station control operator and tagging desk command center.
3. Project close out and documentation.

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ESTIMATED COST for TURN-KEY SYSTEMS

The costs listed below are general estimates based on DCS vendor turn-key pricing. Under a turn-key project, the DCS vendor would provide the system hardware, software, project management, application engineering, field service, training, construction management, and installation.

DCS Replacement Project Cost Estimate							
Budget Year	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	**TOTALS**
DCS Project, Documentation, & Specification Development Costs	$40,000	$345,000	$250,000	$125,000	$120,000	$120,000	**$1,000,000**
DAS & SOE Replacement Costs			$2,750,000	$2,400,000	$0	$0	**$5,150,000**
Simulator Replacement Costs		$100,000	$650,000	$350,000	$50,000	$0	**$1,050,000**
Controls Replacement Costs			$1,425,000	$25,000	$3,100,000	$3,050,000	**$7,600,000**
Job Total	$40,000	$445,000	$5,075,000	$2,900,000	$3,270,000	$3,170,000	**$14,800,000**

RECOMMENDATION for FOX 1/A SYSTEMS

Replacement of the FOX 1/A system is recommended as the initial segment of the plant DCS upgrade project. Replacement is recommended beginning in the 2003-04 budget year with completion scheduled for 2004-05. The replacement data acquisition system (DAS) should be selected to be compatible with the controls replacement system.

The obsolete nature of the FOX 1/A and the time in service of most system components have resulted in a trend of increasing system failures and reliability problems. This trend is impacting system availability. It is not expected to improve. Additionally, the processing and monitoring capability of existing systems is near capacity. Delay of FOX 1/A replacement is an option, but not recommended.

<u>BENEFITS</u>
The replacement of the FOX 1/A system would bring the following benefits:

1. **System obsolescence and reliability issues solved.** Removal and replacement of the existing system with new technology systems would eliminate the availability and reliability problems currently being experienced on the unit DAS systems.

2. **Improved unit monitoring capability.** New technology systems have vastly increased monitoring capability and analysis power, and these systems require significantly less floor space that existing systems. A replacement system would offer could be expected to supply more data, faster, and more reliably than the existing systems with significant expansion capability.

3. **Reduced long-term spare parts and support training costs.** Replacement systems would be selected that would be compatible with the controls replacement DCS systems and in large part use common spares. The current collection of varied systems would be replaced with an integrated system from a single vendor. Elimination of the need to train all systems personnel on a variety of systems would reduce training costs.

4. **Improved data to the plant information system.** The replacement DAS system would provide a standardized, higher capacity data link to the plant information system.

5. **Pre-training and experience in the use of the replacement DCS system technology.** The replacement FOX 1/A systems would use the same type of equipment as the controls replacement systems though implemented for data acquisition only. While this does not replace simulator/controls training, it provides operators with experience on the DCS replacement system hardware in advance of the DCS installation.

Every effort is currently being made to extend the service life of the FOX 1/A systems to the absolute end of OEM or third party support. Current trends, however, indicate that within three (3) to five (5) years such a course will likely result in a serious and extended system failure and a corresponding breach in the availability of measured process data and dependent analytical and predictive data. Accordingly, a project to replace the FOX 1/A should begin by 2001-02.

RECOMMENDATION for SIMULATOR

Purchase of a modern high-fidelity simulator is recommended as part of a plant DCS upgrade. Currently many fossil utilities are investing in simulators to be competitive in a deregulated energy market. There are two main reasons: to improve plant operation, and to aid in changing to a new DCS. Advances in simulator technology have made it possible to have an exact model of a power plant's processes and equipment. This allows the simulator model to be controlled by a copy of the plant DCS software.

<u>BENEFITS</u>
The benefits of a Simulator are as follows :

1. **DCS control testing tool.** DCS controls can be configured, tested, debugged, and tuned on the simulator before the unit outage to change out the control system begins. This reduces the amount of work that needs to be done during the outage and can reduce the overall outage time. Fewer problems bringing the unit back online would be expected. The decrease in outage time <u>could pay for the cost of the simulator.</u>

2. **Operator training tool.** The simulator would allow operators to train on the new DCS before it is installed. The simulator representation of the plant and controls would be very realistic, and it would be an ongoing tool to keep operators "current" on scenarios that are not common during normal operation, helping to maintain high availability.

3. **Unit performance testing tool.** Using the simulator as a testing tool has allowed some plants to ramp faster, operate at lower/higher loads, and avoid trips. "What if" scenarios could be run on the simulator to investigate the results of different operating conditions, or equipment changes.

4. **I&C technician training tool.** The simulator would be a technician training environment for the DCS controls as well as the DCS hardware.

The simulator could be purchased as a turnkey system or as a kit. The "kit" option is the recommended approach. A kit system would involve IPSC personnel assisting the vendor in configuring the controls and plant model, as well as validation of the simulator at various load conditions. Likely, operators, I&C technicians, and engineers would be need to be assigned to do this work. The two options are described below:

1. **Kit Option.** A kit would cost about $1,200,000 and take about 2 years. It would cost about 65 % of a turnkey system. A kit offers the benefit that IPSC personnel would gain an intimate knowledge of the internal details of the simulator design and the plant controls. This knowledge is directly transferable to the control system software and hardware.

2. **Turn-Key system.** The estimated cost of a turnkey system is $1,800,000 and it would take 18 months to complete. The main advantage is a shorter project completion time, about 6 months shorter. Also, fewer IPSC personnel would be required to complete the project.

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CONTROL SYSTEM REPLACEMENT

Replacement of the present control systems must be completed prior to the NOx modifications which will be required by December 31, 2007. This is based on the need for additional control hardware for emissions reduction and obsolescence of the current equipment. The systems listed below are the main plant controls and would function more effectively as a single system. Installation of a unified control system will result in improved control capability. It will also reduce the amount of required hardware for the operator interface, result in decreased maintenance (single system with less hardware to maintain), simplify troubleshooting, streamline training, and a result in a reduction in warehouse inventory.

The following systems are recommended for replacement as part of the DCS upgrade:

1. Foxboro Videospec/Microspec combustion control system (CCS)

2. Bailey Net-90 burner controls system (BCS).

3. General Electric Mark IIA turbine controls (EHC), turbine generator supervisory instruments (TGSI), turbine automatic controls (TAC), and MDT-20 controls for boiler feed pump turbines.

4. Rochester AN-4100 and ISM-1 annunciator and sequence of events recorder (SOE).

The present combustion controls (Foxboro CCS) have had several modifications over the last 14 years which have used spare hardware and software capacity. This will prevent any further significant changes to the combustion controls in the future without a major upgrade.

The General Electric (GE) systems have experienced multiple problems over the years. EHC failures have caused unit trips and TAC failures have occurred during critical times including unit startups. The TGSI systems have had problems with the disk/tape drives subsystem which has required an interim replacement. Additionally, the TGSI operating system is costly as well as cumbersome to modify. The boiler feed pump turbine controls have had problems with calibration drift which cause difficultly with the calibration lineup during outages. A further concern with the GE systems is vendor support. The number of GE personnel remaining who can support these systems is limited.

The Bailey Net-90 systems are becoming obsolete and are experiencing problems with the main processors (logic master modules). These modules are very sensitive to power spikes that cause the memory to be corrupted and require a reload of the operating parameters after system power is cycled.

A new, single control system could tie all of these systems together and provide redundancy, seamless intercommunication, ease of operation and maintenance, and increase the reliability of the unit operation. The enhanced control system will modernize the unit operations providing a new control console for the operators.

<u>Recommendation for Foxboro Videospec/Microspec Controls:</u>
Replacement of the Foxboro systems is recommended as part of the total controls replacement. As indicated above, these systems have no expansion capability. Also, long term vendor support is a

concern. We expect to be able to support this system through 2007; however, Foxboro has transferred support of this equipment to an outside company, Process Control Systems (PCS). While PCS has indicated a potential 10 year support for this system, that support is based on availability of spare parts. Additionally, some of the processor and i/o boards for these systems have custom modifications unique to IGS. This further complicates the support forecast. Parts availability has been a problem for the Foxboro FOX 1/A systems which is the same generation as the Videospec/Microspec. This may indicate that similar, future problem for the Videospec/Microspec. It is certain that the replacement of the Foxboro controls will be necessary well ahead of any regulatory deadlines that require controls modifications or enhancements.

Recommendation for Bailey Net-90 Burner Controls:
Replacement of the Bailey Net-90 Burner Controls is recommended as part of the final segment of the plant DCS upgrade project. This system controls the operation of the pulverizers through control stations on the main control panel. We can eliminate a large amount of hardware and software by combining this system with the main plant digital control system (DCS).

There have been numerous problems with this system over the years. A problem with the grounding in this system caused problems with the flame scanners which resulted in pulverizer trips on loss of flame indication. The Logic Master Modules (LMM) have extended startups due to a loss of program. Power supply failures have caused unit trips and required a modification to a redundant power supply system. It is expected that adequate support for the Bailey hardware will be available until the recommended replacement window. However, the current software used to interface with the Bailey system is obsolete. It is DOS/Windows 3.1 based and will require an upgrade in the near future.

Recommendation for General Electric EHC, TGSI, TAC, and BFPT MDT-20 Systems:
We recommend that the General Electric systems be replaced as part of the final segment of the plant DCS upgrade project. Combining the key control systems into a single system resolves numerous problems associated with the present system.

These systems are expected to be maintainable until completion of the DCS upgrade. But, there is some risk of further intermittent failure due to the remaining, unresolvable problems. The turbine controls have had problems with mercury wetted relays, test circuits that fail, and circuit board component aging causing drifting of settings. The information portion of the system, TGSI, has had problems with the data collection and historical portion of the system. The TGSI to FOX 1/A data link is antiquated causing the update cycle to the information computer to be in excess of four (4) minutes. Discussions with GE to improve upon this communications link have not resolved this situation due to the GE costs required to make changes to our old system (> $100K/unit). The TAC system has had problems since startup. These problems have never been resolved and GE only made ten of these systems due to the problems they encountered. The BFPT controls are an old vintage that are prone to drifting due to the discrete components on the circuit boards. All these systems have problems which would be resolved by replacing them as part of a main plant total DCS replacement.

As indicated earlier, a further concern with the GE systems is vendor support. The number of GE personnel remaining who can support these systems is limited. Also, the turn-around time on repairs and the quality of the actual repairs have been unacceptable in several instances.

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Recommendation for Sequence of Events Recorder (SOE):
We recommend that the Rochester Sequence of Events Recorder be included for replacement as part of the plant DCS upgrade project and installation scheduled concurrent with the FOX 1/A system replacement. Concurrent replacement will balance DCS replacement scheduling and demands during outage periods between the four (4) DCS project phases. SOE replacement will bring all the necessary information into a single DCS platform.

This system was upgraded approximately eight years ago to the current ISM-1 system for audible annunciation and sequence of events. Problems have continually plagued the system with lock-up of the system for no apparent reason. Several attempts by Rochester to repair this problem have not been resolved. This is a critical system when troubleshooting equipment or unit trips.

BENEFITS
The benefits of controls replacement with a coordinated DCS system are as follows:

1. **Improved Control Capability:** These newer systems have finer control capability which enable better control of the boiler, turbine and feed pumps. They have systems available to evaluate tuning parameters, for all control loops, to enhance total system operation. These systems can also be used as a troubleshooting tool to evaluate problems and help with determining resolutions.

2. **Load Ramp Improvement:** The newer controls have a better ability to control key parameters during a load change which allows a quicker load increase or decrease. This may be important in the future with a de-regulated market.

3. **Performance Enhancement:** An improvement in efficiency has been demonstrated in the new control systems. Even though we already have a high heat rate, improved performance will be seen with tighter control of pressure and temperature with the newer boiler controls.

4. **Reduced Hardware:** The newer DCS systems allow a reduction in interface equipment because of the direct connection of instrumentation through the DCS system. This means that recorders, switches, lights, control stations, and indicators will be wired directly to the DCS . This eliminates the equipment and the wiring.

5. **Training Standardization:** Having all the control in a single system minimizes the training requirements. Costs will be reduced and overall training needs decreased.

6. **Warehouse Inventory Reduction:** Total control parts inventory can be reduced significantly by combining systems into a single manufacturer for key control systems.

7. **Central Information Gathering:** All information from each system would come to the new DCS system. No special data interfaces would be required as they are now, ie. TAC, TGSI and SOE data links. Current and historical data would be available for plant personnel to review and evaluate from a single source.

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POTENTIAL ECONOMIC BENEFITS

DCS vendors advocate that a new DCS would reduce generating costs and improve competitiveness in the following areas: improved megawatt ramp rate, O2 improvements, sootblowing reduction, improved availability, reduced maintenance costs, reduced inventory costs, reduced NOx emissions, improved productivity, and lower training costs. Of these, megawatt ramp rate, and improved availability are thought have the largest potential dollar value:

1. **Improved ramp rate:** Many western utilities are upgrading control systems with increased unit ramp rate being a primary objective. An improved ramp rate allows them to be more responsive to dispatch demands and competitively capture "spot market" power sales. IPSC engineering personnel do not have the necessary marketing information needed to estimate the potential benefit of an increased ramp rate.

2. **Improved availability:** A new DCS could be expected to improve availability due to fewer future trips, fewer runbacks, and shorter startup time after trips and outages. The potential benefit could be significant considering that trips and reduced availability are expected to increase as the existing control equipment ages. No estimates for the value of potential benefits have been made.

Maintenance Costs: Maintenance costs on a new system would likely not be less than what IPSC is experiencing now. Past costs have averaged $69,000 over the last 4 years to maintain the Fox 1/A, CCS, RIS, Bailey Net 90, and GE systems. This number was identified from purchase order information (purchases, repairs, rebuilds) assigned to control system equipment codes. Likely, there are some costs that were assigned to the plant equipment numbers rather than the control system equipment numbers and are not reflected in the above total. The table in "Attachment A", Summary of Current System Maintenance Costs, shows that the Fox 1/A accounts for most of the yearly cost.

Future costs would depend on the level of support that IPSC desired from the DCS vendor, but they could be estimated to be from $100,000 to $200,000 per year. This is based on the maintenance agreements that the Navajo and Bonanza plants currently have.

Reduced Spares in the Warehouse: The total number of spare parts required to support a new DCS system would be greatly reduced from the current number now on hand. The DCS would combine systems from several vendors into a system from a single vendor. The cost savings due to a reduced need to stock and warehouse parts has not been estimated. Currently, the warehouse has over $1.5 million dollars in spare control parts (values as assigned in the TIMS system):

Foxboro, 1/A and CCS	$629,200
RIS	140,000
Bailey	111,624
GE	~200,000
Modicon	~500,000
	~$1,580,000

Reduced NOx Emissions. One DCS vendor asserts a potential reduction in NOx emissions of up to 12 % with a new control system. The vendor estimates this would relate to a 4 % reduction in the capital cost of SCR NOx controls or over $2 million dollars. IPSC has not investigated the likelihood that a new control system at our plant would reduce NOx emissions.

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SUMMARY of DCS UPGRADE SITE VISITS

Summary of Plant Visits to Bonanza and Navajo Power Plants
DCS Control Upgrades

Reason for upgrades: Navajo and Bonanza upgraded to a new DCS because of obsolescence of old control hardware and difficulty in maintaining the equipment. Also, upgrades were done in conjunction with plant changes: new scrubbers at Navajo, and turbine and pulverizer upgrades at Bonanza.

Systems upgraded: Both plants have upgraded older controls to a Foxboro I/A DCS system. Bonanza did the project in four steps over 2 years: the DAS (information computer systems), scrubber controls, power block relay logic and BFP controls, and finally the turbine, burner management, and DCS controls. At Navajo, they also did their DAS systems first, then all the controls for each of three units were done, with one unit completed each year during an 8 week outage.

Turbine controls: Both plants replaced their dedicated turbine controls with the controls done in the Foxboro DCS. Both report this has worked well.

Burner Management: Both plants now do burner controls in the new DCS, replacing older dedicated systems.

SER: (Sequence of events recorder, or SOE) Both plants have their SER functions done in the new DCS.

Sootblowing: Bonanza uses sootblowing done in the new DCS. Navajo has integrated the DCS to an older PLC sootblowing system.

PLCs vs DCS controls: Both plants use the new DCS for power block logic (motor control of fans, pumps, etc) rather than PLCs. They also both have their scrubbers run by the DCS rather than PLCs. PLCs are still used in many areas of the plant.

Control Board Replacement: Both plants removed their control (BTG) boards and replaced them with an arrangement of CRTs. The big disadvantage with the computer screens noted by operators is that they couldn't see as much at once. Also, it can be slower using the screens to take action. However, comments by unit operators indicated that they liked the new controls and layout better than the old controls. Direct-wired trip buttons were available for critical equipment. Both plants had touch screens but did not recommend them or use them much, except the touch screen helps to locate the cursor on the screen quickly. Navajo used trackballs and Bonanza used mice for screen pointing.

Navajo used mostly standard graphics provided by Foxboro. At Bonanza operators built custom displays with as much information as possible on one screen. They tried to design the displays so an operator could get to where he needed to go with one mouse click. Both sites seemed pleased with what they had.

New Control Operation: The new controls require less operator intervention and are not operated in manual as much. The unit operators operate scrubbers from the main control room now at each plant. Normally, this requires as much time as running the units. At Navajo, the new controls are very stable,

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and handle runbacks very well. Ramp rate was 5 mw/min before and now 75 mw/min is possible. N0x emissions were unchanged.

Simulator: Navajo wanted a simulator at the time the project was beginning, but could not get approval from all participants in the plant. They now have that approval and are proceeding to procure one. Bonanza purchased a simulator from Esscor as a kit. Much of the modeling was done in-house. It was very successful for controls checkout and initial tuning.

Support of System: Both plants maintain and support their systems with a limited group of dedicated people. Navajo has a system administrator (a former unit operator), and I&C techs assigned to the new system. Bonanza has 2 engineers and 2 I&C techs assigned to their system. Additionally, an operator is the graphics expert. Technicians were pleased with having fewer different systems to learn since several systems have been consolidated into the DCS. Also, there are fewer different parts to warehouse. Each plant indicated a high level of expertise (training and hands-on experience) is needed to support the DCS. Also, both plants have maintenance agreements with Foxboro ranging from $140,000 to $290,000 per year.

Project Management: Navajo's specification and contract was done by the corporate office in Phoenix. Personnel at Page oversaw the installation and startup. Bonanza did their own specification and contract with outside help. Both sites contracted with Forney Systems to move their burner management systems to Foxboro I/A, and both used contract people during the installation for wiring.

Comments on Foxboro: Both sites reported Foxboro has very good hardware and they were pleased with the system and startup. Both said be wary of using Foxboro Cluster I/O. It is cheaper but will not function well in all environments. Both use UNIX for an operating system, and do no recommend using NT.

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Attachment # 1 - Summary of Current System Maintenance Costs

Attachment 1

Summary of Maintenance Costs for Control Systems

(costs on purchase orders, repairs, rebuilds)

System	Unit	Code	Costs FY97-FY98	Costs FY99-FY00	One year (ave) FY97-FY98	One year (ave) FY99-FY00	Average/ year (4 yrs)
Fox 1/A	Both		105699	61160	**52850**	**30580**	**41715**
	1	1INF--0	83079	53710	41540	26855	34197
	2	2INF--0	22620	7450	11310	3725	7518
CCS	Both		32236	26814	**16118**	**13407**	**14763**
	1	1COA--0	21085	17134	10543	8567	9555
	2	2COA--0	11151	9680	5576	4840	5208
RIS	Both		1774	12034	**887**	**6017**	**3452**
	1	1INF--B	1116	8242	558	4121	2340
	2	2INF--B	658	3792	329	1896	1113
Bailey	Both		3962	1824	**1981**	**912**	**1447**
	1	1SGH--0	988	330	494	165	330
	2	2SGH--0	2974	1494	1487	747	1117
GE	Both		25694	5848	**12847**	**2924**	**7886**
	1	1TGF--0	11278	2903	5639	1452	3545
	2	2TGF--0	14416	2945	7208	1473	4340
TOTAL			**169365**	**107680**	**84683**	**53840**	**69261**

****Modicon**	Combined		6912	11347	**3456**	**5674**	**4565**
small part of	1	1COF--0	3108	4987	1554	2494	2024
modicons	2	2COF--0	1017	1358	509	679	594
	9	9COF--0	2787	5002	1394	2501	1947
Modicon	Quantum Upgrade		155000	352000	77500	176000	**126750**

** Most of the Modicon costs are charged to plant equipment numbers other than COF--0. Costs are actually much higher. This happens to a smaller degree for Fox, CCS, Bailey, GE, & RIS , so their costs are higher.

Attachment # 2 - Notes on Bonanza Plant Visit

Fact Finding Tour
DCS, DAS, & Simulator Replacement Project
Bonanza Power Station

Visit to Deseret Generation's Bonanza Power Plant: 14-Sep-00 Notes: J. Burr

Reason for upgrade: Deseret upgraded because of obsolescence of control hardware. They had experieinced support problems with their Westinghouse system. They also had a goal to standardize plant controls into 2 systems. Foxboro and Allen Bradley. They used a step approach by doing their data acquisition system first, then minor systems, then the major ones together with a turbine upgrade and mill upgrade. Plant capacity is now 490 gross, up 50 mw from before.

Systems looked at: Honeywell, good software; Foxboro, good hardware; Westinghouse, was not responsive on info or bid (Ovation is new system)

Systems upgraded: The stepwise approach did have some problems, with getting data between systems. In 1998 they started and did the DAS system with 1200 points and it took 1 year. The next steps: Scrubber controls; relay logic, BFPs; BMS, DCS, turbine, in spring of 2000. Next, they will replace the electrical control board.

Turbine controls: These are now done in Foxboro and they work well. They do use a triconics analog card (has been a minor problem) but now a digital version is out and is better. They have had very few problems with the new controls done by Foxboro. Tim Cosca is the Fox turbine controls guy.

SER: (Sequence of events recorder, SOE) Replaced their RIS with Foxboro, points went from 1300 to 600 or less. ~2/3 point reduction. Now the Seq. Of Events is just a database not prints. Points come to a CP processor, but timing is an issue because Cps are not synced. Should be synced to a satellite or standard time. Print to 1/10 th of a second, but the software records to the milli second level, and this can be dumped out.

Sootblowing: They replaced their old system with Foxboro sootblowing done from a CRT.

Vibration: They replaced their Bentley-Nevada system with one from SKF. Bentley was double the money?

PLCs vs DCS controls: Previously power block logic was done with relays, not PLCs. The replacement choice was between the Fox DCS and Allen Bradley PLCs. The Fox DCS was chosen and this has worked well. Foxboro gateways (integrator 30s) to link to the PLCs are expensive and limited on points. By bringing the logic to the Fox controllers (CPs) they could consolidate better than using PLCs and have redundancy built in. Allen Bradley is cheaper per I/O point but the integration would have cost more, even with non-redundant gateways. From other areas in the plant they have 20 PLCs coming in on 8 Foxboro integrator 30s.

Control Board Replacement: They replaced the control board with a bank of CRTs. One big drawback noted by operators was that they couldn't see as much at once with the screens. Also, they felt it can be slow to go to the desired computer screen when trying to take action. Removing the board and going to CRTs is a paradigm shift that takes getting used to, but operators indicated for the most part it has been good. The new controls require less intervention and are not operated in manual as much. Also Deseret had operators design their graphic screens and most actions are only one page away. In the control room they had 7 workstation screens for Foxboro controls, and one big, large monitor, and they had a sootblowing system screen. They operate their scrubber from the main control room now.

New Control Operation: They have just installed their system this last spring. The plant turbine was also upgraded so many comparisons of how the old controls relate to the new are not well defined. Also, there is still tuning to be done, but they chose to run the plant this summer during the high demand for electricity and tune later. Operators and engineers said they were happy with the new controls.

Historian: They use the Foxboro Aim-Star historian and have 1 ½ months of data available on an optical disk. They turn the disk over for the other 1 ½ months. A hard disk would be better.

Simulator: Much of the modeling was done in-house with help from Esscor, by Larry Jorgensen a shift supervisor with a CS degree. The big plus of the simulator was with controls checkout and controls tuning. It was very successful. Hugh Scigliano from Foxboro used it to check out and tune the controls before loading the controls on the real system.

Support of System: They maintain and support the system with two engineers and two I&C techs assigned to the new system. They indicated other techs will get a chance later to work on the system. A unit operator was the graphics person and still supports that effort. Techs like only having to learn two systems now, Foxboro and AB. They felt that a smaller group of trained and dedicated people was necessary to manage the system. They have a maintenance agreement with Foxboro for ~$140,000 per year. This seems expensive.

Project Management: The spec was done with help of Burns and McDonnel. During the installation they used DTC (a contractor) to do wiring. They advised us to use a digital camera on the bid spec, it helps a lot. It is important to have a database including every termination. They contracted with Forney Systems to move their burner management system and baghouse logic to Foxboro I/A. In their spec, they should have had language to handle change orders and pricing better. With Foxboro there isn't really a fixed price, but one could expect to pay 30% to 40% of the list price.

Comments of Foxboro: Very good hardware. They are pleased with the system and startup. They recommend designing own graphics rather than using standard Foxboro graphics. They do not recommend getting the Foxboro Cluster I/O. For the DCS operating system they use UNIX not Windows NT. They have heard of problems with NT.

Personnel: Robert Strolle- e. engineer 435-781-5733
Mike White- e. engineer
Tom Howells- operator and graphics guy
Kreig Parker? I&C tech
Thomas Wilhem- planner and results tech (e guide)

Visit to Deseret Generation Bonanza Power Plant: 14-Sep-00 Notes: K. Nielson
Attendees: James Burr, Ken Nielson, Alan Williams, & Bill Morgan

Bonanza replaced control systems by standardizing on Foxboro IA for CCS, Burner,Turbine controls and DAS; and Allen Bradley for PLCs. Previously had an array of systems including Westinghouse, Forney, Fisher, Foxboro and other. Controls replacement allow elimination of control board and reduced required operator staffing. The new systems increased information and control capabilities. 3 year phased project beginning with DAS. Simulator was installed and recommended. Recommended having simulator installed 1 year prior to controls. Bonanza pleased w/ new Foxboro IA system and Foxboro support. Further detail is provided below.

Bonanza Site Visit Details
The following list of questions was compiled to review during the site visit:
1. Why were the old systems replaced?
2. Was the replacement system installed in a single phase or multi-phase project?
3. How was the replacement project done?
4. Was an independent Data Acquisition System (DAS) installed?

5. Was the DAS system done at the same time as the Coordinated Control System (CCS)?
6. Did they do the controls or take old controls and transfer them?
7. How long did it take to do the new controls?
8. Who configured the process graphics and operator interfaces?
9. Was a simulator installed?
10. Where in the project chronology was it installed?
11. How was the simulator done?
12. How were operators and system users trained?
13. With operators trained, how much continuing training is done?
14. Is the simulator used to test 'what if' scenarios for the CCS?
15. Were control rooms modified with the new CCS? If so, how?
16. How is support staffing structured for the new DCS, DAS, and Simulator systems?
17. How were support personnel trained?
18. Which/What replacement system(s) were selected? Why?
19. How successful and accepted has the replacement system been?
20. How was replacement project support from the system vendor?
21. How has post installation support been?
22. Does the vendor offer continuing modernization/upgrade support plans?
23. Are these used?
24. What are the details of such this plan?
25. What would be done differently?

Discussions on the replacement project and recorded notes are organized below according to the pre-compiled question list shown above.

1. What were the previous control systems?
    a. Previous to the current systems, Bonanza had Westinghouse controls, Forney burner controls, and an array of control systems and PLCs.

2. Why were the old systems replaced?
    a. Replaced old systems due to support problems from Westinghouse and due to system obsolescence.
    b. In some cases, they had been notified that support for particular components would be dropped within 1 to 2 years.

3. Was the replacement system installed in a single phase or multi-phase project?
    a. New systems part of a multi-year project that began in 1998. Started with the DAS first, then as much of the controls on-line as possible, then the CCS, Turbine, and Burner control systems.
    b. In 1998 the DAS system was installed. Approximately 1200 points in the DAS.
    c. Replaced the scrubber controls about 6 months later followed by the relay logic. Much of this was done on-line.
    d. Replaced the CCS in the spring of 2000. An outage was required for this segment of the replacement project. It was also done concurrently with the replacement of the turbine rotor and some of their pulverizers.
    e. There is a lower outright cost to do all controls at the same time due to the amount of data links required to old systems. But, the phased approach allowed operators time on the IA DAS system while allowing them to use the old familiar controls.

4. How was the replacement project done?
    a. Contracted with AE was done to prepare as specification for the procurement process. However, a modified version prepared by Bonanza technical staff that was more useable and is the basis for the project documents.

b. Specified that replacement systems would be standardized. Though installed in phases, proposals were for all segments of the replacement systems.
c. Project management done by engineering at Bonanza.
d. Much of the system configuration done by DG&T personnel.
e. Simulator development done by in-house support at Bonanza. See more information below.
f. Contractors used in I/O replacement.
g. Controls and system configuration done by Bonanza staff, Foxboro, and Foxboro subcontractors.
h. Graphics built by operations personnel.

5. Was an independent Data Acquisition System (DAS) installed?
   a. The DCS and DAS system are integrated and considered part of the same system. They are separate components of the IA system at Bonanza.
   b. Currently, use I/A for DAS. Use AimStar historian by Foxboro. Started with FoxHistory, but found that system to be unreliable. That was replaced by the Aimstar system.
   c. Likely to go to an off-platform systems in the future to provide desktop access to data.
   d. PC/Desktop access is available to a limited amount of on-site users. PC/Desktop access is available through connection to an AW (applications workstation) to authorized users only.

6. Was the DAS system done at the same time as the Coordinated Control System (CCS)?
   a. No. Though considered now to be different components of the same system, the DAS segment of the system was installed about 2 years prior to the CCS systems.

7. Did they do the controls or take old controls and transfer them?
   a. Rebuilt from the ground up by Foxboro.
   b. Controls were test and pre-tuned on the simulator.
   c. Old terminal blocks were used where possible, but most I/O terminal blocks from previous systems were replaced.

8. How long did it take to do the new controls?
   a. Done by Foxboro (thought to have taken about 1 year.).
   b. Tuning included dumping the controls to the simulator. Then, made changes on the DCS according to what they had done and tested on the simulator. They did not dump the controls back to the DCS.
   c. The tuning was sufficient to allow successful start-up and operation to meet production demands. However, additional tuning will be completed on the on-line system during their fall outage.

9. Who configured the process graphics and operator interfaces?
   a. Operators built and largely support modifications to the DAS graphics. This was very successful and recommended. Minimally, there should be operator involvement in the graphics display creation.
   b. Some graphics simulate old manual controls with added trends and color status indicators.
   c. They do not like the touch screens. While sometimes convenient, they are costly to maintain and reliability is not as high as they would like.
   d. One operator is assigned and acts as the controller up implementing changes and enhancements.
   e. Estimated that 1.5 to 2 man-years were required to build the graphics.

10. Was a simulator installed?
    a. Yes, a Simulator by Esscor.

11. Where in the project chronology was it installed?
    a. Implemented between the DAS and CCS replacement systems.

12. How was the simulator done?
    a. Esscor simulator. The basic simulator 'kit' was received from Esscor and the simulator system was built by Bonanza personnel.
    b. Received simulator for operator training just prior the spring 2000 outage. This was insufficient to allow adequate training time for operations personnel on controls.
    c. Simulator was used for pre-startup tuning. The pre-tuning effort was very successful.

13. How were operators and system users trained?
    a. Operators had one (1) to two (2) years experience with the DAS part of the IA system and the scrubber controls.
    b. They recommended that the DAS be installed a year or two in advance to allow familiarization w/ Foxboro IA before use for start-up and unit control.
    c. Only a month or two of simulator training was available for simulator training prior to restarting the unit.
    d. There were no trips due to operator error. Had one trip due to the failure of an IA system CP (control processor) failure.

14. With operators trained, how much continuing training is done?
    a. So far, work is continuing on the simulator by systems personnel as time permits.
    b. Little additional training has been done. However, operations an engineering personnel would like to see much greater user of the simulator for training.

15. Is the simulator used to test 'what if' scenarios for the CCS?
    a. Not currently, but intend to do so.

16. Were control rooms modified with the new CCS? If so, how?
    a. Yes, manual control boards were replaced with CRTs. Pre-installation of the DAS allowed familiarization w/CRT before manual systems are removed. Plus new controls are good enough to largely eliminate the need for manual interaction for most situations.
    b. Replaced the manual control panels in three (3) phases from 1998-2000. Phased out the control panels. Replaced with a quantity of twelve (12) 21" CRTs and one (1) 46" CRT. The new CRTs are arranged in blocks of four (4) CRTs. Each block of CRTs is separated from the next by a console with hard-wired trip/start buttons and small video screens showing some site locations. The large CRT is ceiling suspended and used for primary trends.
    c. The new CCS eliminated the need to control from the scrubber control room and put those controls in the main control room. However, an AP (application processor) has been located in the scrubber control room to allow control from that location in case there is a communications failure to the main control room.
    d. With the elimination of the control panel, the Rochester sequence of event recorder (SER) and annunciator light boxes annunciation system was eliminated. All annunciation is done from the IA system.
    e. Initially, there was considerable apprehension among operations personnel about this modification. Operations personnel indicated that once they were familiar with the new systems, they have come to prefer them.
    f. With a manual control board, multiple control switches could be activated somewhat simultaneously. With CRTs, good organization and management of control screens has been required to duplicate that capability. However, with the CRT controls, much more operating information is available. Again, display/screen organization and management is critical.
    g. DG&T operations and technical staff were unanimous in recommending that custom screens be developed in-house rather than use the standard Foxboro built screens.

17. How is support and support staffing structured for the new DCS, DAS, and Simulator systems?
    a. Have a support agreement with the TAC (Technical Assistance Center) at Foxboro. Also the utilize the FoxWatch capability that allows a secured remote login access (call back security) to authorized Foxboro support personnel. The contract cost is currently about $140,000/year. Bonanza technical staff seemed very please with this agreement and the support and results that it has yielded. Comments included that Foxboro had provided good response via this program. Without the contract, they found their support calls to be addressed on a lesser priority.
    b. Staffing includes:
        i. Two (2) systems engineers
        ii. Two (2) Dedicated I&C techs for support, backups, etc...
    c. All techs are trained to use and support the system. The ideal plan is to rotate all through the system eventually. However, they largely allow personnel to focus on areas where interests and expertise best serve the company. This seems to have fostered more ownership in care for the job and systems.
    d. Controls changes are initiated by any of the primary four (4) support or engineering personnel. Then prior to implementation on the live side, a review by at least one (1) of the other primary personnel is required.
    e. Technicians are on call on weekends.
    f. With the standardization of equipment, a great deal of the problems with rotation and getting people up to speed on equipment has been eliminated.

18. How were support personnel trained?
    a. Primary systems personnel pre-trained for system installation support.
    b. Other I&C support personnel and system users trained via on-site training class.

19. Which/What replacement system(s) were selected? Why?
    a. Bonanza standardized on Foxboro for controls and Allen Bradley for PLCs. Have found Foxboro easy to use and support.
    b. They use Foxboro for turbine controls and used Foxboro to replace the Forney burner control system, but Forney did the engineering on that portion of the system.
    c. I/O terminal blocks for the Foxboro systems were found to be superior to competitors due to size. Competitors were cited for having large terminal block while the Foxboro system use compact TB sections.
    d. Used MK Engineering system for CEM.
    e. Deseret has employed the automatic soot blowing system from Foxboro.
    f. Though Westinghouse probably had the best opportunity for winning the replacement system, they did not get the bid because they were unresponsive to the bid process, worst prepared in their proposal, and not competitive in cost.
    g. NT v. Unix: Bonanza went with Unix. Found it to be more solid to upgrade and easier to use with the application. Foxboro had had some problems with their NT versions. Bonanza has had one controls related trip. This was due to the failure of a Foxboro Control Processor (CP).

20. Were any PLCs replaced with DCS systems or DCS with PLCs?
    a. Did not use Foxboro to replace any PLCs. Did use Foxboro to replace some relay logic that should have been put on a PLC.
    b. More notes from DG&T on PLC vs. DCS control.
        i. If control can be done on a PLC and the data is not needed on the DCS, then that is cheapest and most efficient (from the system loading perspective) method to follow.
        ii. If the data is needed on the DCS then a gateway will be needed between the DCS system and PLC. There is a data capacity limit on gateways. The cost of PLC to gateway to

DCS configuration is about equal with the DCS to DCS control module. As such elimination of the PLC and control directly with the DCS control module is a viable option.

iii. Control by the DCS with a pass through to the PLC to the process is not recommended. That configuration introduces an additional 2 points of failure plus the loading/system speed impact of the gateway.

21. How successful and accepted has the replacement system been?
    a. System has been reliable. Only one trip attributable to controls. This was due to the failure of a CP hardware module and not a failure due to controls malfunction.

22. How was replacement project support from the system vendor?
    a. Excellent.

23. How has post installation support been?
    a. Excellent.
    b. Support contract and Foxwatch support has been very responsive and is recommended.

24. Does the vendor offer continuing modernization/upgrade support plans? If so, are these used?
    a. A support contract is in place with Foxboro.
    b. Contract does not include gradual modernization of new systems.
    c. Possible option for such available from Foxboro.

25. What are the details of such this plan?
    a. No information at this time.

26. What recommendations for a new project of this type?
    a. Ensure the at least 10-15% spare i/o capacity is built purchased with the new system. Recommended at least on spare slot per i/o TB pack.
    b. Write in pre-agreed methods and costs for escalation of support and installation assistance should such escalation be required.
    c. On change orders or needs for additional material, write in pricing restrictions or guarantees for the purchase of additional or future equipment. 30-40% off of list is not an unusual discount.
    d. Ensure that the vendor will supply functional, logic and detailed schematic layout drawings of the new systems and controls. Foxboro provided basic logic drawings. But AE worked with Foxboro on some controls and provided much more useable and workable detailed schematics and functional diagrams.
    e. Ensure that software upgrades during the project implementation time are included and automatic during the project implementation. This will prevent having to purchase software upgrades for previously installed systems when implementing the later phases of the project.
    f. Also, a means for routine upgrades may be built into maintenance support agreements.
    g. Used a database similar to our Fox 1/A database to build and pre-configure the point databases for the new system. This was especially useful to contractors doing the wiring changes from the Westinghouse or other terminal blocks to the Foxboro TBs.
    h. Install simulator earlier that happened with their schedule.

<u>SUMMARY</u>

The visit to the Bonanza power station was very informative. It provided an opportunity to see the results of a controls and data acquisition system replacement project. The Bonanza DCS/DAS replacement project was pursued in a phased approach. It included the replacement of the I/O capability of the old systems and the installation of a simulator for training and pre-startup tuning.

Phase 1 installed the DAS system. Phase 2 brought the installation of DCS capability for areas that would allow on-line installation. Phase 3 installed the primary CCS, turbine, and burner control systems. That phase required a unit outage and was planned to coincide with a major unit outage in which the turbine rotor and some unit pulverizers were replaced.

The project was initiated due to obsolescence and lack of capacity in the previous systems. Foxboro was selected and the replacement for DCS systems. Allen Bradley was selected as the replacement for PLC systems. Previous systems included: Westinghouse, Forney, Fisher, Foxboro and others.

The DCS replacement project allowed replacement manual switch control boards. Control room monitoring capability included primarily CRT based operator interface. Monitoring of processes from remote or back-end control rooms was relocated to the main unit control room. This resulted in a reduced requirement for operator staffing. Operations personnel indicated that the use of CRTs for control and elimination of the manual control boards was a significant change, but was successful and now largely preferred. Old control boards allowed the actuation of multiple switches somewhat simultaneously while CRT commands could only be done one operation at a time from a single screen. The use and availability of multiple CRTs largely compensated for that advantage. And, as display design and CRT usage patterns improved with experience, operations staff indicated that they expected the CRT system to be fully superior to the manual control panels. They further indicated that the added responsibility of monitoring back-end and outer area operation from the main control room had not impeded their ability or quality of control. They attributed this to the improved control capabilities of the new DCS systems and increase in available data to the operator through the new systems.

The new systems increased both information and control capabilities. Both technical and operations personnel indicated that installation of the DAS prior to the DCS allowed valuable on the job pre-training in the use of the IA systems prior to controls replacement.

Operations personnel were utilized for the majority of controls and information displays construction (See attached examples.). Both operations and technical personnel indicated that this was a very successful and recommended method. A unit operator was designated as the primary authority for screen changes and construction. Modifications to controls and information screens were coordinated through or completed by that operator. Operators indicated that display design varied significantly from standard Foxboro displays. A primary goal of the Bonanza screens was to get anywhere needed with one mouse click. Touch screens were installed, but operators preferred the mouse and keyboard interface.

The simulator was purchased from Esscor which is a sibling company to Fxoboro under Invensys. Bonanza chose to purchase and Esscor "kit" simulator and build the simulator system internally. The simulator was completed about 1 to 2 months prior to the major unit outage wherein the primary controls systems would be replaced. It was used successfully for pre-tuning the new controls. Bonanza personnel recommended having the simulator completed about 1 year prior to controls to allow for more operator training and better development of tuning.

The new DCS and DAS systems at Bonanza are considered different components of the same system. Systems modification projects and overall engineering responsibilities are handled by systems and controls engineers. System maintenance responsibilities are handled by I&C personnel. With IA installed plant-wide as the DCS standard, new and continued training requirements for I&C personnel has been streamlined. All I&C personnel were trained on IA and Allen Bradley. However, specific I&C personnel are assigned to specific areas of responsibility. Since all equipment is the same, technicians with one area of responsibility can support most repair in other areas. Support for complex after-hours or weekend problems in areas outside of the shift I&C personnel's primary area of responsibility could be escalated by means of "on call" support by engineering or I&C personnel primary to a given system. Bonanza personnel indicated that allowing technicians to migrate to specific areas per interest and expertise had resulted in greater ownership in their jobs and areas of responsibility.

They would like to eventually rotated everyone through the DCS support. But, there are no plans to do this in the short term future.

Changes to the on-line systems are completed by either the engineers or technicians assigned with primary support for a given system. Typically, there will be one (1) or two (2) engineers and two (2) technicians with primary authority for any given area. Changes on a system could not be implemented without review of one (1) or more of this primary support group for a system. Once a change has been made, procedures include providing notification and updated documentation for the change to other engineering and I&C personnel.

Bonanza personnel were pleased with the new Foxboro IA systems and with Foxboro support. They indicated that both installation project support and post installation support have been very satisfactory.

Attachment # 3 - Notes on Navajo Plant Visit

Fact Finding Tour
DCS & DAS Replacement Project
Salt River Project - Navajo Generating Station

Visit to SRP's Navajo Power Plant: 27-Sep-00 Notes: J. Burr

Reason for upgrade: Navajo upgraded because of obsolescence of old hardware, and installation of new scrubbers. Previously they had an old Bailey 820 analog control system with GE Turbine controls. They had a turnkey contract with Foxboro that covered installation of equipment over 3 years starting in 1997. First they replaced their DAS (information system). They upgraded 3 units. The first was done in 1997, the second in 1998, and the last in 1999. Each was done in under 8 weeks during an outage.

Systems they looked at: The corporate office did the spec, vendor selection, and contract. Foxboro was chosen, but Honeywell, Bailey, and Westinghouse were considered. The control system at SRP's Coronado Plant was replaced with Honeywell shortly before Navajo's project. It was reported things haven't worked out as well (with Honeywell) as with Foxboro. SRP has since used Foxboro on several other plant upgrades.

Systems upgraded: In 1997 they began with DAS systems. (Previously, they had an old Honeywell information systems). This required a new link to their old controls, which became unnecessary after controls and DAS were all Foxboro I/A and there were 500 points not needed. The cost was ~$16 million for unit and scrubber controls for 3 units. What was in 16 Bailey cabinets is now in 3 Foxboro cabinets. After the DAS, the Scrubber controls, BMS, DCS, turbine, SER and annunciator done all at once.

Turbine controls: These are now done in Foxboro and they work well. They have had very few problems with the new controls done by Foxboro. The controls for the BFP turbines are done with Woodward and interface with Foxboro. They said Woodward's support isn't so great and would like to replace the controls with Foxboro I/A.

SER: (Sequence of events recorder, or SOE) Replaced with Foxboro. They use the "causes of trips" only and have 50-100 points. Other items are alarms. They have a 3rd party package (Logmate) to determine sequence on a CRT.

Sootblowing: This is done with previously existing Allen Bradley PLC 5. It is integrated to the Foxboro and use Fox graphics for operation. Operators decide what sootblowing is done, it is not automatic.

O2 Measurement System: They have a Thermox AMTEK system and are happy with it.

PLCs vs DCS controls: They have power block logic for motor control of fans, pumps, etc done with Foxboro controls rather than PLCs. They recommend this in the main area of the plant. It is a more reliable way to do the control. They also use Foxboro in their scrubber controls rather than PLCs.

Control Board Replacement: They removed their control board (BTG) and replaced it with an arrangement of CRTs. The big disadvantage noted by operators was that they couldn't see as much at once with the screens. But overall the unit operators indicated that they liked the new controls and layout better. In the control room they had 5 workstations with 2 screens each for the main plant controls. They also 4 other screens for Alarms, plant LAN, and 2 scrubber/back end screens. There are direct-wired trip buttons for critical equipment. They have touch screens but do not recommend them or use them much, except the touch screens help to locate the cursor on the screen quickly. They would like the cursor to be more visible. Also the desk part of the station in front of the CRTs and keyboard should be larger for writing. Operators felt like the CRT stations should be in more of a U shape to help view things quicker. They used trackballs and were pleased with them.

Termination cabinets were installed in place of the BTG control board to handle wiring that had come directly to the board. Operators used a basic-generic simulator for training from Esscor but they were not pleased with the usefulness of this. The Foxboro controls guy, John Benoyer came and did a 2 week school for the operators. Initially only one unit was on the new control system, followed by another unit each year. Most of the operators preferred to work on the with the new controls once they became familiar with them.

New Control Operation: The new controls require little intervention and are not operated in manual as much. The unit operators operate the scrubbers from the main control room now, and normally requires as much time as running the units. The new controls are very stable, and handle runbacks very well. Ramp rate was 5 mw/min before and now do 75 mw/min is possible.

More on software: Foxboro provided a program for operators called "Operator Watch". Also they had an annunciator software program from Foxboro called "WASP". When a big upset in the unit occurs, up to 200 alarms may come in. Smart alarming is available but has not been configured. This should have been done up-front. Foxboro also provided a starting and loading program for unit startups. For maintenance issues, Foxboro has a preventative maintenance package which includes equipment runtimes.

Graphics: Graphics were built in Foxboro's "Display Manager" product, Foxboro now has a new product out called "Foxview". They used Foxboro's standard screen layouts for controls, which allow up to 8 control face plates on a page in combination with trends of other items in any of the 8 locations. They use face plate pages during normal operation, but use lots of process graphics during startups/shutdowns. The graphics were built mainly by operators.

Historian: They use the Foxboro legacy historian (not Aim-Star) for the control room but have an additional package called RTX (similar to PI) for engineers and managers to access plant data.

Simulator: The plant wanted a simulator from Esscor at the time the project was beginning, but could not get approval from all participants in the plant. They now have that approval and are proceeding to procure one. They indicated, a simulator would have been a big benefit prior to the installation and startup of the controls.

System layout: They have 3 processors dedicated to the DAS (information) and 11 control processors all of which are redundant. The make have a rule not to control with DAS points, so they only use control points.

Support of System: They maintain and support the system with a small group of dedicated people, none of which were engineers. The engineers they currently have at the plant don't work much on the controls. The people working on the system volunteered to for the project before it began. They have a system administrator (a former unit operator) who was a former unit operator, and 2 or 3 I&C techs dedicated to the new system. An additional tech was just reassigned to another plant. These people are still hourly and they maintain the system out to the field wiring. There have been some problems lately with technicians who are not working on this system feeling they are missing out. The system technicians we talked to, indicated that a high level of expertise (training and hands-on experience) is required to support the system. They said this takes years, not weeks, to acquire. Hardware failures are very rare after startup, and when techs are called out, the problem is usually due to field problems. Control system changes are done rather informally. Changes are discussed with technicians, operators, results people, and engineers, then implemented.

Project Management: The spec and contract was done by the corporate office in Phoenix. Personnel at Page oversaw the installation and startup. Early in the project, engineers from the corporate office inventoried all control and wiring cabinets including everything in the control panels. During the installation contract people were used for wiring.. They contracted with Forney Systems to move their burner management system to Foxboro I/A. They specified to Foxboro, that Fox engineer John Benoyer to do the controls configuration. This was because they were familiar with him and he is one of the best. They indicated much of the success of the controls depends on the person that does them. The scrubber controls were done by the contractor for the scrubber (using Foxboro I/A) and they are less pleased with them. They have a full service maintenance agreement with Foxboro for ~$240,000 per year.

Comments on Foxboro: Very good hardware. They are pleased with the system and startup. Unlike Bonanza, they mostly used standard Foxboro graphics for control, configured to their needs. They have some Foxboro Cluster I/O for some cabinets. It is cheaper but will not function in hot environments. Also, they have had problems with connectors coming loose. They use UNIX for an operating system , and do no recommend using NT.

Personnel: Bob Swapp, system administrator, former unit operator
Willie Barber I&C tech
Jim Mace I&C tech

<u>Visit to SRP's Navajo Power Plant: 27-Sep-00 Notes: K. Nielson</u>
IPSC Attendees: James Burr, Ken Nielson, Alan Williams, & Bill Morgan

Navajo replaced DCS and DAS systems with Foxboro IA, Allen-Bradley is the PLC standard, and RTX is the off-platform plant historian. Retained Woodward for BFPT controls, but trying to migrate to Foxboro. CCS replacement precipitated by scrubber project. Previously, had Bailey controls w/Forney burner management system. New DCS allowed elimination of unit control boards, reduced required operator staffing, and increased DAS/DCS capability. 3 year project done by unit w/DAS & DCS replaced at same time. Simulator not purchased initially, though now approved for installation. Strongly recommended installation of Simulator prior to the DCS. Navajo was pleased w/ new Foxboro IA systems and support. Further detail is available below.

<u>Navajo Site Visit Details</u>
The following list of questions was compiled to review during the site visit:

1. Why were the old systems replaced?
2. Was the replacement system installed in a single phase or multi-phase project?
3. How was the replacement project done?
4. Was an independent Data Acquisition System (DAS) installed?
5. Was the DAS system done at the same time as the Coordinated Control System (CCS)?
6. Did they do the controls or take old controls and transfer them?
7. How long did it take to do the new controls?
8. Who configured the process graphics and operator interfaces?
9. Was a simulator installed?
10. Where in the project chronology was it installed?
11. How was the simulator done?
12. How were operators and system users trained?
13. With operators trained, how much continuing training is done?
14. Is the simulator used to test 'what if' scenarios for the CCS?
15. Were control rooms modified with the new CCS? If so, how?
16. How is support staffing structured for the new DCS, DAS, and Simulator systems?
17. How were support personnel trained?
18. Which/What replacement system(s) were selected? Why?
19. How successful and accepted has the replacement system been?
20. How was replacement project support from the system vendor?
21. How has post installation support been?
22. Does the vendor offer continuing modernization/upgrade support plans?
23. Are these used?

24. What are the details of such this plan?
25. What would be done differently?

Discussions on the replacement project and recorded notes are organized below according to the pre-compiled question list shown above.

1. Why were the old systems replaced?
    a. Obsolete control systems and the scrubber installation project precipitated the replacement of their control systems.
    b. Navajo had obsolete Bailey controls on their units. Unit control panels were all manual which limited the availability of this information.

2. Was the replacement system installed in a single phase or multi-phase project?
    a. Multi-year project with installation synchronized with the installation of the scrubbers beginning in 1997 and ending in 1999.
    b. DAS and DCS systems on a given unit were replaced at the same time during outages to implement the newly installed scrubber systems.

3. How was the replacement project done?
    a. Replacement was synchronized with the outages required for scrubber implementation.
    b. Did project one unit per year over three years. Each unit was done within an eight (8) week outage.
    c. Went from Bailey to Foxboro IA. I/O for the control systems was also changed to IA nodebus technology.
    d. On BFPT controls, Navajo is moving from MAC to Woodward, but would like to migrate all controls to Foxboro.
    e. Sootblowers are allen Bradley (Coal Slocum?). IA is connected through an integrator. Sootblowers starts are not automatically initiated, but rather initiated by Operator action.
    f. Replaced 16 Bailey cabinets with 3 Foxboro cabinets.
    g. Foxoboro IA 51B systems were installed.

4. Was an independent Data Acquisition System (DAS) installed?
    a. Yes and No.
    b. Each unit has a separate IA system. Though part of the same IA system, there are dedicated DAS and DCS components.
    c. During installation, the DAS portion of the system was installed first, then the DCS. Since the DAS and DCS systems started separate but are now essentially part of the same system, a rule of thumb is applied that controls are only done on and from controls points/components and data functions are loaded only on the DAS components/points.
    d. Prior to the IA system, no sequence of events recorder was available except for light box windows. This was all replaced by Foxboro IA. This system replaced a 775 point annunciator plus an additional 700 points.
    e. Foxboro has a package called WASP (Window Annunciation Software Package) which is the virtual creation of light box windows on a CRT. Users can click on a virtual light box for information on that point. Navajo has the WASP system; but instead of the WASP, they use a plant overview display with a blinking equipment primitives to indicate troubled equipment or conditions. They find this to work better than the annunciation windows or simulated windows.
    f. The sequence of events capability in IA is millisecond. But they indicated taht care needed to be taken that the SOE is not configured faster than the actual point updates.
    g. Navajo has 52 points configured for SOE. These are points for parameters or equipment that will cause a unit trip. Everything else recorded in the regular IA system for determining what happened after a trip and in what order.

h. DAS is a rolling historian. Navajo uses the "legacy" IA historian.
i. RTX is their long-term, "off-platform" archive system with 2 second resolution. Mostly provides process trends and includes an Excel interface. RTX is a company that was built by former Foxboro persons.
j. All RTX servers are located in the unit control building in a computer room back of the unit control room.
k. They have other Foxboro software or applications packages for preventative maintenance and run-time totalization, reports, etc.
l. Will be replacing their alarm printers with PCs using "Logmate" software.
m. Fiber optic links connected the scrubber and unit IA nodes.
n. Inter-unit connection is available to authorized personnel on the IA system although this option is used only when necessary. Navajo implemented a rule of thumb that controls changes to be done for a specific unit should be done on and from IA application workstations on that unit even though interconnection to APs from other units was possible.

5. Was the DAS system done at the same time as the Coordinated Control System (CCS)?
   a. Yes, the DAS was replaced during the same outage as the DCS on a given unit. However, during the outage, the DAS was installed first, then the CCS. A second DAS system was installed during a later 2 week outage.
   b. Problems with going with the DAS first is the need for intermediate links to the old system that will then be discarded when the balance of the old equipment is replaced.

6. Did they do the controls or take old controls and transfer them?
   a. John Benoyer (Venoyer) of Foxboro did their unit controls.
   b. Scrubber controls were done by SWE and ABB who received the hardware from Foxboro and did the controls themselves.
   c. On controls, Foxboro used a model from Texas Utilities for basic controls model. Then the controls were adapted to the specifics of the Navajo units.
   d. Burner management was done on IA by Forney. Forney just took what was in the old system and rebuilt those burner controls in the IA system.
   e. Philosophy generally followed by Navajo is that no equipment is started automatically. This is primarily for safety.
   f. IA has a good modicon interface, but there is some slow down in the scan rate with any interface and each interface to another system requires an "integrator" device (or gateway which introduces not only the slow down, but an additional point of failure.
   g. Troubleshooting all done in software on IA

7. How long did it take to do the new controls?
   a. Installation was done during an eight (8) week outage. However, a significant amount of pre-configuration of controls was completed by Foxboro.
   b. Installed and initially tuned during unit outages for installation of the new scrubbers.

8. Who configured the process graphics and operator interfaces?
   a. Navajo personnel built own displays on the DAS system using Foxboro face-plates for control.
   b. Display Manager by Foxboro was used. Foxboro now has the FoxView package which has a greater capability for customization.
   c. Displays were largely built by an operator on the installation group. That individual remained in the IA support group.

9. Was a simulator installed?
   a. No and Yes. No simulator was installed prior to installation of the DCS/DAS systems.

However, Navajo has just recently approved a simulator.
b. Navajo personnel indicated that it would have been much better to have before startup.

10. Where in the project chronology was it installed?
    a. Approved for purchase in the coming year.

11. How was the simulator done?
    a. N/A

12. How were operators and system users trained?
    a. Initial startup was done by the systems team.
    b. Regular operators trained on the job during the start ups wby working in conjunction with the installation/systems team.

13. With operators trained, how much continuing training is done?
    a. Thought that the use of the simulator would have prevented some unit trips and will help avoid trips in the future. Need to have operator s familiar/2nd nature on using the new DCS systems. The new systems handle most conditions in auto mode quite well. Lack of training caused some operators to take action during events when none was required. Continued training with the simulator was thought to help operators from over-reaction during process events.
    b. Navajo systems personnel indicated that the simulator was necessary to keep people sharp. With the new control systems, problems and start-ups are much fewer and further between.

14. Is the simulator used to test 'what if' scenarios for the CCS?
    a. As yet, N/A.

15. Were control rooms modified with the new CCS? If so, how?
    a. All manual board components and the entire manual control panel previously in use at Navajo was replaced by the IA CRT command station.
    b. Arrangement of CRTs included 14 CRTs in a bent or slightly curving formation. Six (6) CRTs were vertically, double-stacked in the center of the command station with an additional pair of CRTs vertically stacked on each flank. Each pair of these CRTs were supported by an IA workstation processor (WP). These ten (10) CRTs were dedicated to unit control and monitoring. On one end of the command station, an additional four (4) CRTs were mounted horizontally at eye level. The first two (2) were IA CRTs supported by one (1) WP. These were dedicated to scrubber control. The next CRT was PC connected providing access to the plant LAN and maintenance management system. The final CRT was for an IA application processor. An additional two CRT sized panels with hardwired buttons for operator action were located in the operator command station. These included hardwired unit and turbine trip buttons. Trackball and mylar keyboards were provided for each system pair of WP CRTs. Two (2) alarm printers and a tagging PC were place adjacent to the command station and available for unit operator use.
    c. As the DCS was replaced and operators came up to speed, the operators have preferred the new IA systems to the control panel.
    d. Application and workstation processors were UNIX workstations.
    e. Though used initially after the scrubbers came on-line, scrubber control rooms are no longer used.
    f. Each unit operator handles a portion of the outside area controls. There are three units; hence, three UOs with a control command station as descibed above per unit. Each UO has one or two auxiliary operators available assist as required.

16. How is support staffing structured for the new DCS, DAS, and Simulator systems?
   a. Met with the three (3) systems personnel: Bob Swapp, Jim Mace, and William Barber.
   b. Two (2) came from I&C and one (1) from Operations. The individual from Ops. did the graphics, then was assigned system administration. The two (2) technicians from I&C technicians worked with Foxboro on the controls and now are responsible for controls changes and maintenance. They are no longer part of I&C or Operations.
   c. They had four (4) systems people initially, but one has since transferred SRP central office in Phoenix.
   d. They strongly recommended a closed system support group due to the learning curve involved with the systems. They handle support issues and controls changes.
   e. Then they turn problems that deal with the field devices to I&C for action.
   f. When questioned about support depth and after-hours support, they indicated that as yet there had been no problems. Some after hours support issues were handled on a call-out basis.

17. How were support personnel trained?
   a. All systems personnel were fully trained at Foxboro. The two I&C systems technicians do all controls modifications.

18. Which/What replacement system(s) were selected? Why?
   a. New system are all Foxboro IA for CCS, turbine, and burner controls. This has been a benefit as replacement parts are homogeneous.
   b. Honeywell, Bailey, Westinghouse, and Foxboro were all bid competitors on the project. Foxboro won with low bid.
   c. Unix is recommended over NT for the control system operating system. Their opinion was that UNIX was more secure and stable for this type of application.
   d. Allen Bradley is their PLC plant standard (Model 540)
   e. Navajo uses Tri-Sen controllers for the turbine valve servos.
   f. All plants with the Salt River Project are upgrading their coordinated control systems. The first was Coronado that went with Honeywell. That system, while successful in meeting project goals, has been less than satisfactory in overall performance in comparison for Foxboro which has been the selected standard for other SRP plants.

19. How successful and accepted has the replacement system been?
   a. The new DCS didn't effect NOx output.
   b. Improved ramp rate form 5 MW/min to a typical capability of 50 MW/min and a maximum capability of 75 MW/min.
   c. While initially uncomfortable with the CRT based control panel, all operators indicated that they now thought they were better than the panels they replaced. Different techniques and methods of information and controls management was required by the operators in using the CRT base systems.

20. How was replacement project support from the system vendor?
   a. Foxboro support has been great. Excellent system engineering, installation support, and hardware support.
   b. Used Foxboro for replacement of I/O wiring. This turned-out very well.
   c. Navajo indicated the greatest level of satisfaction in the segments of the project completed in which Foxboro was the primary contractor.

21. How has post installation support been?
   a. Reported very satisfied with Foxboro support.

b. They have a "Foxwatch" support contract.
c. Support cost per year with Foxboro is +$240,000.

22. Does the vendor offer continuing modernization/upgrade support plans?
    a. Navajo not utilizing this type of service from Foxboro. However, they recommended that such upgrades during the installation phases might be addressed in the specification to ensure all components and/or software up to date at the conclusion of the installation project.

23. Are these used?
    a. At present they are not using such as service from Foxboro.

24. What are the details of such this plan?
    a. N/A

25. What would be done differently?
    a. Cluster I/O has mixed review. Some problems w/ connectors staying attached and with bad I/O indication to the DCS. Cluster I/O in a bigger qty of I/O for a given space. If they were to do it over, they would use FBMs instead of cluster. Each card handles 64 digital or 16 ananlog inputs. It is somewhat cheaper. Cluster I/O cards are very heat intolerant.
    b. Operators at Navajo did not like the touch screens very well. Absolutely not used for start and stops on equipment or changes on set points. OK to use to find cursor and to change screen displays.

<u>SUMMARY</u>

The visit to the Navajo power station was very beneficial. Navajo had selected the Foxboro IA system for the replacement DCS system. This allowed IPSC personnel to focus on project issues, sequence, and technology transition issues rather than comparisons of different DCS vendor products. This was consistent with the intent of the visit.

The Navajo plant visit provided the perspective of a replacement project for the DCS and data acquisition systems in a larger plant/unit environment. While done over a multi-year project, DCS and DAS systems for a given unit were replaced during the same outage. This contrasted with the phase installation approach applied at Bonanza.

The Navajo DCS/DAS replacement project began in 1997 and was completed in 1999. It included the replacement of the I/O capability of the old systems. It also included the installation of DCS systems in the newly installed scrubber systems. These systems were also IA systems. A simulator was not installed prior to the DCS/DAS systems. One had been planned but installation was delayed by project participants. A simulator is currently approved for purchase and installation. It will be used to provide continued training for operations personnel and for testing of tuning and controls changes. Navajo personnel indicated that continued operator training with the simulator was considered essential as the new DCS systems minimized trips and unit events and accordingly minimized exposure to unit start-ups and event reaction training.

The DCS/DAS replacement project was initiated due to obsolescence and lack of capacity in the previous systems. These factors along with the project to install scrubbers on the Navajo units precipitated the installation/replacement of the DCS systems. Foxboro was selected as the replacement for the boiler, turbine and burner control systems. The previous systems included Bailey and Forney. Allen Bradley is their PLC plant standard (Model 540). Navajo uses Tri-Sen controllers for the turbine valve servos. BFPT controls are being moved from MAC to Woodward, but they would like to migrate all controls to Foxboro. Sootblowers are Allen Bradley (Coal/Cole Slocum?). IA is connected through an integrator. Sootblowers starts are not automatically initiated, but rather initiated by Operator action. Navajo systems personnel indicated that the replacement of the previous systems with Foxboro systems had streamlined spare parts and support issues.

The DCS replacement project also caused replacement of the manual-switch control boards. Control room monitoring capability now includes a CRT based control panel for operator interface. Operations personnel indicated that the use of CRTs for control and elimination of the manual control boards was a significant change, but was successful and now largely preferred. However, they indicated that the usefulness of touch screens was limited to locating the cursor. Operators indicated that the CRT based control panels introduced some challenges to get "at–a-glance" status of the operating units as compared with the manual control panel. With use and training, however, they had come to prefer the CRT based systems. They also indicated that greater quantities of data could be viewed from the CRT based panels than was available from the manual control panels.

Monitoring of processes from remote or back-end control rooms started in the remote area control rooms. It had since been relocated to the main unit control room. Unit Operators had auxiliary operators available to assist with unit control. Like Bonanza, they indicated that the added responsibility of monitoring back-end and outer area operation from the main control room had not impeded their ability or quality of control. They attributed this to the improved control capabilities of the new DCS systems and the increase in available data to the operator through the new systems.

Similar to Bonanza, the new systems increased both information and control capabilities. System support personnel indicated that the installation of a simulator prior to the DCS/DAS system would have allowed valuable pre-replacement training for operations personnel.

An operations person was utilized to configure the controls and information displays (See attached examples.). Both operations and technical personnel indicated that this was a very successful and recommended method. This person was later designated as the DAS administrator and the primary authority for screen changes and construction. Display design followed largely the Foxboro face-plate style. Touch screens were installed, but operators preferred the mouse and keyboard interface.

The DCS controls changes and administration was completed by the two (2) systems technicians. They were originally from the I&C department. The three (3) systems support personnel formed a defacto IA systems support group. Foxboro was also retained under maintenance contract for additional system maintenance support. There are currently no plans to rotate support other personnel through the DCS/DAS system support group.

Navajo personnel were pleased with the new Foxboro IA systems and with Foxboro support. They indicated that both installation project support and post installation support have been very satisfactory.

Attachment # 4 - Alternative Project Schedules

DCS Replacement Timetable w/ Accelerated Simulator Schedule

Calendar Year	* Denotes Approximate Date of Annual Major Outage 2000 Jul, 2001 Jan	Jul, 2002 Jan	Jul, 2003 Jan	Jul, 2004 Jan	Jul, 2005 Jan	Jul, 2006 Jan	Jul, 2007 Jan	Jul, 2008 Jan
Budget Year	FY2000-2001	FY2001-2002	FY2002-2003	FY2003-2004	FY2004-2005	FY2005-2006	FY2006-2007	FY2007-2008
FOX 1/A Replacement Schedule	Continued Technology investigation	Complete preliminary engineering, budget, and develop project specifications, issue RFP, Select Vendor.	Purchase and Install U1 FOX 1/A System.	Purchase and Install U2 FOX 1/A System.	*Alternative Deferred Schedule - Project completion in 2004-05*	*Alternative Deferred Schedule - Project completion in 2005-06*	*Alternative Deferred Schedule - Project completion in 2006-07*	12/31/07 New NOx Requirements on 12/31/2007 Replacement must be completed prior to NOx deadline.
Accelerated Simulator Replacement Schedule		Budget/Spec for Simulator	Install Simulator and develop controls on simulator. Budget for delivery of controls logic for CCS, GE, Bailey, BFP, and SER systems.	Complete controls development on simulator and test controls. Controls logic delivered from DCS vendor for use and tuning on Simulator by Nov. 2003	Operator Training			
CCS, Turbine, BFP, and Burner Managment Systems Replacement Schedule			*Accelerated Replacement Schedule - Accelerated 2 years.* Beginning of controls replacement could be accelerated to this point with the delivery of a turn-key simulator system.	*Accelerated Replacement Schedule - Accelerated 1 year.* Controls expansion, coordination w/DAS replacement, or CCS reliability problems may require acceleration of replacement. Replacement must be completed prior to NOx deadline.	Budget for CCS, GE, Bailey, BFP, and SER replacement systems hardware.	Purchase and Install U2 CCS, GE, Bailey, BFP, and SER replacement systems.	Purchase and Install U1 CCS, GE, Bailey, BFP, and SER replacement systems.	

DCS Replacement Timetable w/ DCS Schedules

Calendar Year

** Denotes Approximate Date of Annual Major Outage*

2000 Jul | 2001 Jan | Jul | 2002 Jan | Jul | 2003 Jan | Jul | 2004 Jan | Jul | 2005 Jan | Jul | 2006 Jan | Jul | 2007 Jan | Jul | 2008 Jan

	Budget Year	FY2000-2001	FY2001-2002	FY2002-2003	FY2003-2004	FY2004-2005	FY2005-2006	FY2006-2007	FY2007-2008
ACCELERATED 1 YR	FOX 1/A Replacement Schedule	Continued Technology investigation	Complete preliminary engineering, budget, and develop project specifications, issue RFP, Select Vendor.	Purchase and Install U1 FOX 1/A System.	Purchase and Install U2 FOX 1/A System.	*Alternative Deferred Schedule - Project completion in 2004-05*	*Alternative Deferred Schedule - Project completion in 2005-06*		12/31/07 New NOx Requirements on 12/31/2007 Replacement must be completed prior to NOx deadline.
	Accelerated Simulator Replacement Schedule		Budget/Spec for Simulator. Budget for delivery of controls logic for CCS, GE, Bailey, BFP, and SER systems.	Install turn-key Simulator. Load, tune, & test controls from DCS vendor. Controls logic delivered from DCS vendor for use and tuning on Simulator by Mar. 2003	Operator Training				
	Accelerated Controls Replacement Schedule			*Accelerated Replacement Schedule - Accelerated 2 years.*	Budget for CCS, GE, Bailey, BFP, and SER replacement systems hardware.	Purchase and Install U1 CCS, GE, Bailey, BFP, and SER replacement systems.	Purchase and Install U2 CCS, GE, Bailey, BFP, and SER replacement systems.		
ACCELERATED 2 YRS	FOX 1/A Replacement Schedule	Continued Technology investigation	Complete preliminary engineering, budget, and develop project specifications, issue RFP, Select Vendor.	Purchase and Install U1 FOX 1/A System.	Purchase and Install U2 FOX 1/A System.	*Alternative Deferred Schedule - Project completion in 2004-05*			12/31/07 New NOx Requirements on 12/31/2007 Replacement must be completed prior to NOx deadline.
	Accelerated Simulator Replacement Schedule		Budget/Spec for Simulator. Budget for delivery of controls logic.	Install turn-key Simulator. Load, tune, & test controls from DCS vendor. Controls from DCS vendor by Mar. 2003.	Operator Ttraining				
	Accelerated Controls Replacement Schedule			Budget for CCS, GE, Bailey, BFP, and SER replacement systems hardware.	Purchase and Install U2 CCS, GE, Bailey, BFP, and SER replacement systems.	Purchase and Install U1 CCS, GE, Bailey, BFP, and SER replacement systems.			

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Proposal No. 00275-021
Letter No. IPA-11022009

Intermountain Power Agency

Re-Powering the Intermountain Power Project

Mr. Saif Morgri
IPP Operating Agent Staff
Department of Water and Power
111 North Hope Street, Room 1263
Los Angeles, CA 90012-2607

Dear Mr. Morgri:

Sargent & Lundy, L.L.C. (S&L) is pleased to submit our proposal for studying all five tasks associated with re-powering the existing units and/or re-powering the site as defined in the Intermountain Power Agency's (IPA) Request for Proposal (RFP) entitled, "Repowering the Intermountain Project".

I. Introduction

We understand that this study is part of IPA's overall strategic plan to develop a strategy to reduce existing CO2 emissions (not to exceed 1,100 lbs/MWHr rate) and meet future generation demand. The project consists of evaluating a range of alternative technologies and operating scenarios described in Tasks 1 to 5 listed in the RFQ. We are also prepared to provide input to the Intermountain Power Project Facilities Strategic Plan Development Team as they under take the development of a decision matrix on the future of Units 1 and 2; enhancement of Intermountain Power Project (IPP) energy resource, including renewables; a decision matrix on the Northern Transmission System (NIS) and Southern Transmission System (STS) targeted on the IPP's future use; and development of the IPP site and resource securities for future value-added users.

As stated above, our proposed scope is for all five tasks. S&L may be the only firm with the credentials to perform all five tasks with credibility because S&L has performed similar studies for other Clients, and has designed and built these kinds of plants recently: all of which are operating successfully. Out recent work includes:

- Modifying boilers and balance-of-plant equipment for fuel switches. We are especially knowledgeable about western fuels and gas conversions.
- Designed/built new gas fired peaking and combined cycle facilities.

- Retired existing boilers (coal and oil) and converted these plants to combined cycle units by repowering each unit with the additional of combustion turbine (CT) and heat recovery steam generators (HRSG).
- Designed/built solar plants.
- Designed/built an IGCC plant.
- Designed/built nuclear units.

More details of S&L's experience including examples of other similar studies and operating power plants are described in the thumbnails listed for the key team members within each task write up in Section II and in Section V of this proposal.

More importantly, we believe that S&L is uniquely qualified to perform this repowering study because:

- A S&L team will be assembled that possess very specific and recent experience pertinent to each task(s) on previous projects. In addition, we have strengthened our team for Task 1 by joining up with Babcock & Wilcox Power Generating Group (B&W), the IPP boiler OEM, to support Task 1 to identify in more detail the specific boiler modifications required for the gas conversion including any fatal flaws.

- These key team members along with the S&L support staff have proven experience and capabilities that include:

  - Comprehensive knowledge of new boiler design and conversions for firing and co-firing with gas and solid opportunity fuels, including petroleum coke, refinery off-gas, landfill and waste treatment plant gas, agricultural and organic process waste, and wood and wood waste.
  - Extensive experience in condition assessment and plant betterment and upgrade engineering for existing generating facilities.
  - Significant experience in re-powering of existing units, converting oil-fired and coal-fired units to gas-fired.
  - Industry-leading experience in electric and cogeneration plant design and procurement, providing unsurpassed knowledge of technology and capital costs for utility and industrial boilers,
  - Unmatched experience in environmental compliance planning and engineering for new and existing steam and electric production facilities,
  - Expansive knowledge of regulatory and permitting issues and requirements at both federal and state levels.

In addition, some of the proposed team members have worked with IPA and LADWP in developing Unit 3 at the IPP site in 2003 and 2004. S&L performed all of the initial studies, which included new unit layout, technology selection, regulatory support, general arrangements, schedule development, and a detailed cost estimate for a new 950 MW coal unit. This activity has given S&L significant insight into the existing IPP facility.

The proposed team members also have performed project feasibility studies and project development work during 2003-2005 for LADWP related to their existing and future gas-fired fleet. The major portion of the work was to re-power portions of the existing Haynes and Scattergood plants. S&L developed different options to convert the existing gas-fired boilers units to more modern and efficient combustion turbine facilities using as much of the existing facilities as possible from a cost and regulatory perspective. S&L also developed an Engineer, Purchase and Construct (EPC) bid document for LADWP to proceed with the repower the Haynes plant.

We have already checked with the Kern Gas Company (Kern), the only natural gas pipeline that would be accessible for this IPA project. The existing pipeline runs from Wyoming to Las Vegas/Los Angeles through Utah and operates at 1200-1330 psi. With minor upgrades to their system, Kern could supply more than enough gas required for full conversion of IPP (both units), to gas. Kern is currently considering building a lateral pipeline from their main line to the Western Energy Hub for strategic storage. This Western Energy Hub is a salt dome formation near Delta, Utah that the Owners are looking for customers to store natural gas/other hydrocarbons after they extract the salt. Kern is very interested in sharing the cost of the new line.

As requested, we have prepared each task as a stand alone task. Since S&L is bidding on all five tasks, we have also identified certain benefits for a cumulative or combined effect to the various tasks, including accounting for the cumulative effect of water usage for Tasks 2-5 with the existing Units 1 and 2 remaining in operation in Section VI of this proposal. In addition, we have also identified the selected key team members and corresponding relevant experiences within each task.

Described below is a proposal scope of work

II. Scope of Work/Approach/Assumptions

S&L is proposing to perform the below tasks in strict compliance with IPA's RFQ; this includes proposing each task and corresponding pricing as stand alone activities. In Section IV and VI of our proposal, we describe the cost savings if S&L is awarded all five tasks. In addition to these cost benefits, S&L will also ensure that each task is prepared on the same basis with the same design criteria so that there is an accurate relative comparison of the different alternative technologies and operating scenarios. Using more than one engineering firm to develop costs, emissions, schedule may introduce a variability between the various options that result from the subject matter and different options/values used by the various firms.

Since IPA's RFQ did not include any scope for evaluating transmission capability, we have not included this scope.

Task 1 – Coal to Gas Change over

Task 1 is to modify the existing Units 1 & 2 to allow a change in fuel from coal to natural gas. We understand that a "repowering" of Units 1 & 2 to a very large combined cycle plant is not an option for Task 1.

We have identified with B&W (our partner) four technologies or options that IPA should consider to accomplish switching Units 1 & 2 from coal to natural gas listed as follows:

1. Identify the minimum required boiler modifications needed with reduction in unit capacity and performance.
2. Identify all boiler alternations needed to mitigate performance and efficiency loss.
3. Examine the possibility of adding two new gas fired boilers.

4. *Investigate the potential for windbox repowering.*

We have selected Option 1 listed above because it is the most economical option to proceed with on this Task 1. Prior to developing the conceptual feasibility letter report, we will perform a fatal flaw review and provide a summary report to the IPA.

Phase note that if IPA is interested in pursuing any of the other options, Options 2 through 4, we can provide pricing for these other options.

If the Option 1 is considered to be feasible, we will provide the following:

- Identify the minimum required boiler modifications needed.
- Supply budgetary cost and schedule to implement modifications.
- Review the reduction in unit capacity and performance.
- Estimate possible NOx, CO, and VOC emissions.
- Consider the prospect of future conversion back to coal in modifications.

As discussed above, we have already identified that Kern could supply more than enough gas required for full conversion of IPP (both Units), to gas.

In addition, we will describe the major changes in plant operations and maintenance due to the change in fuel source. Also, we will provide a table summarizing the pros and cons of converting the fuel from coal to gas.

Proposed Team

Mr. William Rosenquist will coordinate with B&W on this task. Mr. Rosenquist currently heads up our Conceptual Design Group, which supports the early development of new units and retrofit concepts such as, gas-firing from coal-firing and combustion turbine repowering. The group is involved in conceptualizing all types of generating units, PC, CFB, IGCC, combined-cycle, simple cycle, biomass, and solar. His group has recently been involved in several coal to natural gas conversions as well as gas turbine repowering projects. The group serves as a technology resource for the client-dedicated project teams and brings the knowledge of recent conceptual design development on over 40 projects in the last 7 to 9 years.

The early phase development work involves coordinating many different engineering disciplines, such as boiler specialists, material handling, air quality control, water treatment, geotechnical, transmission line interconnect, unit performance calculations, and capital O&M costs. S&L has current performance information on the various CT vendors; latest models; in addition to having worked on natural gas conversions we have added B&W to out team for input on the impacts to the boiler.

Mr. Rosenquist is very familiar with the Intermountain Units and Site as he was Project Manger for the development of new PC Unit 3 at the site. The work included technology assessment, layouts, performance, switchyard tie-in, and the technical inputs that supported the air permit application for Unit 3.

If S&L is selected on all five tasks, Mr. Rosenquist will be a consultant in all the other tasks as well.

Since the boiler being proposed for modifications are B&W units. B&W will be able to work off of the original design information and drawings to minimize the expense associated with setting up a base performance model for these boilers. More information on B&W is included in Section V of this proposal including a list of their recent engineering studies for boiler conversion to natural gas.

Task 2 – New Combined Cycle Generating Facility
S&L will prepare a conceptual feasibility letter report for adding one or more new combined cycle power blocks at the existing IPP site. We will not perform a fatal flow analysis for this task.

The combined cycle facility will utilize state-of-the art gas and steam turbine technology. We have on-going projects with the major combustion turbine suppliers and keep current with their latest offerings. We will start out with the minimum target capacity of 900 MW. A combined cycle facility with duct burners can be used not only as a base loaded plant but also for cycling and load shaping as well. However, the peaker units described in Task 3 would provide more load shaping flexibility. Our proposal is based on using the commercially available F or G combustion turbine technology. Please note that the largest H combustion turbine machine is currently going through the testing phase now. We understand that for Task 2, the existing Units 1 and 2 will remain generating.

Before we develop the deliverables requested in the RFP and listed below, we will address the following five scope items:

1. Determine if the existing IPP site is suitable for a combined cycle power plant. Our previous work on Unit 3 will help to expedite this process.
2. Determine if enough water for cooling and other usage is available at the site or will a new water reservoir be required.
3. Evaluate the impact of using dry cooling instead of water. As a minimum, address impact on efficiency, capital cost, O&M cost and capacity.
4. Determine if there is a sufficient gas supply available.
5. Identify any critical issues.
6. If the site is suitable for a combined cycle power plant, identify the likely size of a unit or units in gross and net MW output that could be considered. For this item, we will assume that no additional property and water will be considered.

   Once we determine that a combined cycle facility is feasible for IPP site, we will develop the following conceptual deliverables for the minimum target capacity of 900 MW:

   1. Conceptual Design, description of major equipment and conceptual layout
   2. Capital Cost Estimate (± 25% accuracy)
   3. Annual Cost Estimate
      a. Fixed O&M Cost
      b. Variable O&M Cost
   4. Level 1 Project Schedule (Gantt Chart), including
      a. Planning and Development
      b. Environmental and Regulatory
      c. Detailed Design
      d. Construction
   5. Estimate of emissions per MWh for CO_2 and NO_x, SO_x and Mercury per mmBtu

6. Net Plant Heat Rate and output at 3 load cases

Proposed Team

Mr. Yee will lead Task 2. Mr. Yee is a Senior Manager at S&L with over 35 years of power plant engineering experience. He has served as project manager for a number of clients and has successfully managed over 1,000 backfit/betterment/upgrade/environmental/new generation projects. He developed a system-wide NOx compliance strategy for South Carolina Electric & Gas Company. He has managed a number of conceptual/preliminary engineering projects for Mirant, i.e., provided conceptual/preliminary designs and studies associated with simple cycle, combined cycle and coal-fired power plants. Mr. Yee completed successfully (on time and under budget) the addition of two peakers using GE LM6000 technology for the City of Tallahassee. This scope included conceptual/preliminary engineering, procurement and detailed design scope. More recently, Mr. Yee repowered the City of Tallahassee's Hopkins Unit 2, retiring the existing oil fired Unit 2 boiler, to a combined cycle facility using GE 7FA technology for the combustion turbine. This repowered Unit 2 was declared commercial on June 2, 2008, on-time and under budget. S&L's scope included conceptual/preliminary engineering, procurement (major equipment as well as balance-of-plant) and detailed design. If IPA wants to read more in regards to this Hopkins repowering project, please see the Combined Cycle Journal, 2Q/2009 entitled, "Hopkins: Combined – Cycle Repowering Reduce Fuel Cost, Decreased Emissions". If requested, we can forward an electronic copy of this article. The Hopkins Repowering Project was awarded the "2009 Pacesetter Plant Award". Currently, Mr. Yee is completing a detailed design for a 1x1x1 combined cycle facility using an air cooled condenser as the cooling source.

The following proposed key team members will be supporting Mr. Yee on Task 2.

Mr. Steven Warren is one of S&L's Combustion Turbine Specialist. Mr. Warren will provide support to the project team as the combustion turbine specialist. Mr. Warren is a senior manager in our Fossil Power Technologies group and has over 23 years of power engineering experience with most of his tenure working on combustion turbine related projects. A few of these projects include El Dorado (Nominal 500 MW, 2x1 F-Class CT design with ACC) and Sand Hill Energy Center (Nominal 500 MW 2x1 F-Class CT design). He has participated in the procurement of a number of combustion turbines. Mr. Warren was also the S&L project manager for the LADWP Haynes Unit 5 & 6 Repowering work.

Mr. Ken Davis, who is a Senior Principal Consultant, is responsible for directing and coordinating financial and economic work for all new units and retrofit concepts, including gas firing from coal firing and combustion turbine repowering. He has over 40 years experience in the power industry directing economic and financial committing services.

Mr. Edwin Giermak, who is a heat balance specialist, is responsible for the evaluation of thermal heat and mass balances for conventional power plants as well as simple cycle, combined cycle gas turbines, and/or cogeneration designs. His work involves the determination of fuel heating values, plant heat rates for different operating conditions, and performance characteristics of combustion turbine generators, boilers, heat recovery steam generators (HRSG), steam turbine generators, and steam condensing/cooling systems. Results of his evaluations are documented through the preparation of heat balance diagrams using computer-aided techniques, tables that summarize information for comparison purposes, and reports that discuss conclusions and recommendations. Mr. Giermak also completed the heat balance performance evaluations on the new PC Unit 3 at the site. He was also involved in the LADWP Haynes Units 5 & 6 repowering work. He has more than 25 years of experience in the electric power industry and is a Registered Professional Engineer in the State of Illinois.

As discussed previously, Mr. Rosenquist will be a consultant on Task 2 as well, providing his valuable knowledge of the site. Please see Task 1 for his thumbnail.

More discussions of S&L combined cycle experience are in Section V.

Task 3 – Combustion Turbine Natural Gas Peaker Units

1. S&L will prepare a conceptual feasibility report for adding new combustion turbine natural gas peaker units at the existing IPP site. We understand that this Task 3 will not require a fatal flaw review.

   We will utilize the state-of-the-art gas turbine technology. Since the peaking units will be used as a power load shaping tool for the renewable energy, such as wind and geothermal deliverable to the IPP site, we will work with IPA to determine what the profile is in order to determine the size of each peaker, the number of peakers as well as the required operating characteristics of the combustion turbine. We will consider using the LM6000 machine, approximately 48 MW, or the LMS100 size machine, approximately 100 MW. A combination of both types of peakers may be required to fit IPA's load profile. We understand that for the peakers, the total minimum target capacity is also 900 MW. We also understand that for this Task 3 the existing Units 1 and 2 will remain as is in operation.

   Before we develop the deliverables requested in the RFP and listed below, we will address the following six scope items first:

   - Determine if the existing IPP site is suitable for combustion turbine natural gas peaker units.
   - Determine if enough water for cooling and other usage is available at the site or will new water resources have to be acquired.
   - Determine if there is a sufficient gas supply available.
   - Identify any critical issues.
   - If the site is suitable for combustion turbine natural gas peaker units, identify the likely size of a unit or units in gross and new MW output that could be considered. For this item, we will assume that no additional property and water will be considered.
   - Provide a white paper as to how the peaker units can be utilized as a load shaping tool for the renewable energy delivered to the IPP switchyard.

   We expect based on our knowledge of the site, that the amount of water, land and gas available, is suitable for combustion turbine natural gas peaker units. The more important question is, are these combustion natural gas peakers the best shaping tool. Some municipalities use gas fired reciprocating engines for shaping and distributed controls.

   When we fully determine that the combustion turbine peakers are feasible for the IPP site, we will develop the following conceptual deliverables:

7. Conceptual Design, description of major equipment and conceptual layout
8. Capital Cost Estimate, (± 25% accuracy)
9. Annual Cost Estimate,
   a. Fixed O&M Cost

   b. Variable O&M Cost
10. Level 1 Project Schedule (Gantt Chart), including:
   a. Planning and Development
   b. Environmental and Regulatory
   c. Detailed Design
   d. Construction
11. Estimate of emissions per MWh for CO2 and NOx, SOx and Mercury per mmBtu
12. Net Plant Heat Rate and output at 3 load cases

Proposed Team
We are proposing the same key team members as Task 2. Please see thumbnails in Task 2.

Task 4 – Renewable Generating Facility

The purpose of the Task 4 is to focus on the possible solar uses at the IPP site; identify the most feasible option(s) for solar generation, and provide or high level conceptual design and cost estimate for a single solar technology. In developing this solar option, we will address the following items:

1. Is the existing IPP site suitable for solar technology?

   We will determine if the site is suitable for solar technology.

   a. Solar Insolation
   Solar performance will be calculated for solar parabolic trough and tower using the Solar Advisor Model (SAM) software (Version 3.0, June 2009). The SAM software calculates the size and performance for a parabolic trough plant based on hourly values of solar radiation from the National Solar Radiation Data Base (NSRDB). The NSRDB contains modeled and measured solar radiation for 1961 to 1990. Data from the NSRDB and the National Climate Data Center (NCDC) for the closest location to the identified site will be used. Solar performance for PV will be calculated using the PV System PVSYST v4.37 computer software and/or the SAM software described above. PVSYST 4.37 contains meteorological and PV system components in the database, including data from NSRDB.

   b. Topography
   Topographic maps will be reviewed to determine if the proposed site is suitable for solar technology. We will review the topography for each type of solar technology; trough, tower, dish and PV. For example, for parabolic trough the solar collector assemblies must be installed on level ground with about a $\pm1\%$ grade over the length (terraced levels are acceptable) or tower has more relaxed grading requirements.

   c. Land Coverage
   Based on the results of the solar performance study and type of solar technology, we will determine the land area required.

   d. Infrastructure
   We will review the location of infrastructure (water, gas and transmission). The water and gas usage for each solar technology will be estimated.

2. Explain any limitations that are identified.

   Based on our review of the site and solar technologies, we will identify and explain any pertinent limitations. This will include solar resource, topography, state of commercialization of the solar technology, infrastructure, etc. The limitations for each technology will be identified.

3. If the site is suitable for solar technology, identify the size in gross and net MW output without additional land and water requirements.

   We will provide the size in gross and net MW for the suitable solar technologies. The output from the Solar Advisor Model performance review will also include:

   - The average hourly Direct Normal Insolation (W/m2) by month and hour.
   - The expected hourly energy shape for a representative day for each month of the year for each technology.

4. Provide the type of solar technology or combination that will be suitable for the IPP site.

   Based on our review we will identify the type of solar technology suitable for the IPP site. Solar technologies reviewed will include: parabolic trough, tower, dish and PV.

   We will also review integration of solar with the combined cycle option. ISCC (integrated solar combined cycle) offers a number of potential advantages such as:

   - The incremental cost of increasing the size of the steam turbine is less than building a complete stand-alone solar power plant.
   - Net annual solar-to-electric efficiency is improved because the solar input is not waiting for the turbine plant to start-up.
   - Solar output will offset normal reduction in performance of the combined cycle power plant during hot periods, reducing the need for duct-firing.

The preliminary evaluation prior to starting the conceptual design as identified above will be provided in a study report. The details will be sufficient to understand the applicability of solar technologies to the IPP site. In addition to the written letter report, a matrix will be included in the letter report identifying the solar technologies and comparison to the IPP site.

Based on S&L's evaluation of the most feasible option for solar power at the IPP site, S&L will select a single solar technology and create a high level conceptual design for the project, including:

1. Conceptual Design, description of major equipment and conceptual layout
2. Capital Cost Estimate
3. Annual Cost Estimate
   a. Fixed O&M Cost
   b. Variable O&M Cost

4. Level 1 Project Schedule (Gantt Chart), including
   a. Planning and Development
   b. Environmental and Regulatory
   c. Detailed Design
   d. Construction
5. Estimate of emissions
6. Net Plant Heat Rate and Generation at design

Proposed Team

Mr. Robert (Bob) Charles, who is a Senior Principal Consultant, has worked as **Project Manager** on the majority of our solar consulting projects and heads up the solar consulting practice. Mr. Charles will lead this study using his 38 years experience in design, engineering, power plant operations. Mr. Charles directed the Sargent & Lundy team that performed our recent assessment of solar parabolic trough, power tower and dish solar technology costs and forecasts for Sandia National Laboratories. He was personally responsible for the technical evaluation of power tower technology. He is currently the project manager for our ongoing solar consulting work, including the Owner's Engineering services for development of large scale parabolic trough plant in the Southwest U.S., battery storage for a 50 MW PV plant, and ongoing due diligence reviews of all solar technologies.

Mr. Charles will be supported by the following team:

Mr. Joseph (Joe) Smith, who as a Senior Consultant, is responsible for performing technical evaluations of potential power plant systems and equipment. Mr. Smith also has significant solar experience and was the technical lead for our 2003 and 2008 update of our assessment of solar parabolic trough, power tower and dish solar technology costs and forecasts for Sandia National Laboratories. He prepared the original performance assessments for our review of the Mexicali Solar combined cycle project, the ISCCS appraisal for the World Bank, and a number of solar integration to conventional power plants (simple cycle, combined cycle and coal fired) studies and conceptual designs. Overall, Mr. Smith has 35 years experience in the analysis, design, engineering, and management of power plant and related facility projects. Currently he is the technical lead for providing Owner's Engineering services for development of a large scale parabolic trough plant in the Southwest U.S. and ongoing due diligence reviews of solar technologies.

Mr. Patrick Geenan, who as a Consultant, is responsible for performing due diligence reviews of project performance, budgets, and contracts, including assessment of project construction, operation, fuel supply, and market risks. He has developed conceptual designs and high level cost estimates for several configurations (varying from 100 MW to 500 MW) of parabolic trough plants in the Southwest United States. He has also worked on several solar power technology assessments.

Mr. Kenneth (Ken) Davis, who is a Senior Principal Consultant, is responsible for directing and coordinating financial and economic work for solar engagements. Mr. Davis was S&L's lead financial consultant for our 2003 solar technology assessment for the DOE and developed the financial models used to determine the levelized energy costs for the different solar technologies for our solar consulting projects. He directs the economic and financial consulting practice of S&L's Consulting Group and has over 40 years experience in the power industry.

Mr. Charles, Mr. Smith, and Mr. Davis were the principal authors of the NREL "due diligence- like" analysis of parabolic trough and power tower solar technology cost and performance for the Department of Energy and National Renewable Energy Laboratory. Projects teams for solar projects also include qualified specialists throughout the company as required (e.g. permitting, emissions, geotechnical, civil, thermal heat balance, water balance, transmission & distribution, etc.).

Publications

"Solar-Thermal Power Plant Design and Construction Review", Sargent & Lundy General Power Conference, Chicago, Illinois, March 1990

'Apply latest Technology at Solar-Powered Generating Plant (co-author), Power magazine, April 1990

'Assessment of Concentrating Solar Power Technology Cost and Performance Forecasts', Electric Power Conference, April 2005

Sargent & Lundy, LLC, 'Assessment of Parabolic Trough and Tower Solar Technology Cost and Performance Forecasts', Golden, CO: National Renewable Energy Laboratory, October 2003. Report No. NREL/SR-550-34440)
(Full text available at: http://www.nrel.gov/docs/fy04osti/34440.pdf)

More discussions of S&L solar experience are in Section V.

Task 5 – Other Options

Sargent & Lundy will prepare a cursory evaluation of constructing and operating a nuclear power unit or units at the existing IPP site. The evaluation will be based on utilization of one of the following five state-of-the-art nuclear plants for which a design has been certified or is being reviewed for certification by the U. S. Nuclear Regulatory Commission, and which have been chosen for use in at least one Combined Operating License Application:

- General Electric Advanced Boiling Water Reactor (ABWR)
- General Electric Economical Simplified Boiling Water Reactor (ESBWR)
- Westinghouse Advanced Pressurized Water Reactor (AP1000)
- AREVA U.S. Evolutionary Pressurized Water Reactor (US-EPR)
- Mitsubishi Advanced Pressurized Water Reactor (APWR)

As indicated in the RFP, a conceptual design will not be developed. Instead the following topics will be addressed:

1. Capital costs
2. Operating costs
3. Time frame
4. Site suitability
5. Proximity issues
6. Unit output and heat rate

Capital Costs: S&L will summarize the publicly available data on the overnight capital cost (2009$s) of new nuclear technology. The average overnight costs and the range of publicly available estimates will be provided. Overnight capital costs include the direct and indirect costs of labor, materials and equipment used to construct the plant, plus owners costs, such as land costs, development costs, permitting fees, preparation of the Combined Operating License Application (COLA), financing fees, legal fees, project management, environmental studies, interconnection studies, and market studies. The overnight capital costs will not include escalation during the construction period nor interest during construction given the schedule uncertainty.

Annual Costs: S&L will estimate, on a top-down basis, the annual fixed operation and maintenance (O&M) costs ($/kW/yr) and the variable costs ($/MWh). An expected and range of fixed and variable O&M costs will be provided. Estimates will be based on publicly available sources, S&L internal databases, and S&L judgment and experience.

Time Frame: S&L will provide an estimate and range for the schedule duration from the beginning of conceptual engineering to the Commercial Operation Date (COD). The time frame will include the time needed to obtain environmental and regulatory permits.

Site Suitability: S&L will assess the suitability of the IPP site taking into account the following issues. Fatal flaws will be identified.

- Ground acceleration (based on design assumption for existing units of 0.20 g for 20 seconds, and other IPA provided data)
- Water requirements: A macro-level water balance assessment will be conducted. Both quantity and quality will be assessed using client-provided data.
- Security requirements
- Population density
- Site size, assuming IPP site size of 4,164 acres. Separation issues associated with operating the existing coal units until the nuclear unit is commissioned will be identified and assessed.
- Accessibility of the site by rail for construction materials and equipment, and for nuclear fuel during operation
- Spent fuel handling and storage

Proximity Issues: S&L will identify and assess proximity issues with the proposed Mangum Energy LLC gas pipeline and storage facility.

Unit Output and Heat Rate: S&L will provide the gross and net MW output for each of the five nuclear plant designs, and estimate the likely size or range of sizes of nuclear capacity that could be accommodated at the IPP site. S&L will also provide an estimate of the fuel burn-up rate associated with each design.

The cursory evaluation of a nuclear power unit at the IPP site will be led by Kurt Neubauer. Mr. Neubauer is a Principal Consultant in Sargent & Lundy Consulting and has over 20 years experience in power plant design and development in both nuclear and fossil technologies. Mr. Neubauer has recently conducted a number of Independent Engineer reviews for nuclear projects seeking DOE loan guarantees and has been directly supporting the development and conceptual design activities for a nuclear project in Texas.

Mr. Mike Launi and Chris Ungate will assist Mr. Neubauer with the evaluation. Mr. Launi is a discipline manager of the Nuclear Technology& Regulations Division with 29 years of power plant experience. His responsibilities include coordinating the preparation and licensing review of design change packages for various modifications on nuclear-fueled generating stations, and managing the nuclear licensing, radiological analysis and fire protection groups. He also performs liaison with governmental agencies, vendors, clients, and other divisions within S&L. Mr. Launi has recently supported the preparation of four Combined License Applications (COLAs) and one Early Site Permit Application (ESPAs) for different clients.

Mr. Ungate is a Senior Consultant in Sargent & Lundy Consultant and has over 30 years experience in engineering and planning for electric utilities which includes IRP's. His experience includes reviewing and evaluating potential greenfield or plant expansion options, the viability of siting and permitting new nuclear, coal, gas, wind, solar, biomass or other alternative generation, the prospects for purchase of existing assets, and the potential for partnering with other load serving entities or power generators. Mr. Ungate led a comparative analysis of nuclear technologies for a major Midwest utility, and conducted studies of publicly available estimates of the cost of new nuclear technologies for clients. He also has participated in the preparation of Combined Operating License Applications and Early Site Permit Applications for several S&L nuclear clients.

Both Mr. Launi and Mr. Ungate are currently participating in updating a report on the Current Status and Trends of Nuclear Power Generation Technologies for the Electric Power Research Institute (EPRI).

Similarly, S&L can include one additional option for Task 5, a cursory evaluation of IGCC facility for the IPP site, using an approach similar to the nuclear option. We can provide a firm price if IPA is interested in pursuing this IGCC option. S&L has designed the Wabash River IGCC facility which has successfully operated for many years.

Please note that the option of "repowering" the existing IPP Units 1 and 2, i.e. retire the existing boiler and convert the two units to a very large combined cycle facility by adding a number of combinations of combustion turbine/HRSG trains has been eliminated as an option for Task 5. This was based on the pre-bid questions and responses where IPA has clarified for Tasks 2 through 5, Units 1 and 2 will remain operating as is.

III. Study Schedule

The study schedule for each task is given as follows:

Task 1

- Complete fatal flaw analysis three weeks after receipt of purchase order (PO) and the first (kick-off) meeting.
- Submit a draft letter report ten weeks upon receipt of PO and the first (kick-off) meeting.

Task 2

- Complete feasibility two weeks after receipt of the PO and the first (kick-off) meeting.
- Submit draft letter report six weeks after receipt of PO and the first (kick-off) meeting.

Task 3

- Complete feasibility one week after receipt of the PO and the first (kick-off) meeting.
- Submit white paper three weeks after receipt of IPA's load profile.
- Submit draft letter report eight weeks after receipt of PO and the first (kick-off) meeting.

Task 4
- Submit draft letter report six weeks after receipt of PO and the first (kick-off) meeting.

Task 5
- Submit draft letter report six weeks after receipt of PO and the first (kick-off) meeting.

IV. Trips

We have included three trips per task as requested in the RFQ. Please note that we consider the first meeting to be a kick-off meeting. Each trip will consist of 2 people for one day. Each trip cost includes man-hours and travel expenses. The total cost of the three trips for each task is $14,250. With separate awards for the five tasks to five different firms, the total travel cost adds up $71,250.

If S&L is awarded all five tasks, we would include three trips where one trip will consist of three people for one day and two of the trips will consist of two people for one day for a total cost of $16,590, a savings of $54,660 as compared to separate awards to five different firms.

V. Project Team/S&L Experience Summary

S&L understands the importance of this project to IPA and is proposing a very experienced project team as one can see from the thumbnails included within each task description in Section II of this proposal. A number of the proposed key team members have worked with IPA and LADWP in developing Unit 3 at the IPP site in 2003 and 3004. Also, we have proposed some key team members having worked with LADWP on project feasibility studies and project development work.

Mr. Jack Daly is the proposed Project Director on this IPA project. Mr. Daly was also the Project Director on both the development of Unit 3 at the IPP site and the number of project feasibility studies and project development work for LADWP.

Mr. Daly has over 30 years of power plant experience. Mr. Daly has been very active in the development of new coal units across the USA over the last three years. Projects include 6 new coal units in Arkansas, Utah, Florida, Wyoming, Iowa and Wisconsin. Mr. Daly directed the project strategy and execution for conceptual design and permit application for all of these plants and is in the middle stages of the detailed design for the project in Wyoming.

Mr. Daly has also directed the design of several new combustion turbine power plants located in the Midwest and Northeast United States and the retrofit of particulate collection devices for two units at the General Gentleman Station and Unit 3 at the Weston Station. In addition, Mr. Daly has directed several strategic studies aimed at determining future generation needs, selecting generation technologies, selecting new plant sites and looking at various retrofit options such as repowering existing plants. Mr. Daly has also directed three DCS retrofit projects.

Mr. Yee is the proposed project manager for this IPA project. Please see his thumbnail in Section II, Task 2 of this proposal. He will be supported by the leads identified for each task as described within each task in Section II of this proposal.

Bock Yee References:

Robert McGarrah, Manager of Power Production, City of Tallahassee, Phone 850-891-5535

- Added two new LM6000 peakers
- Repowered Hopkins Unit 2

Steve Wodke, Manager, Duke Energy, Phone 317-776-8351

- Significant Upgrade of the Wabash River Station – this coal unit was scheduled to be retired

Detail resumes are available upon request.

S&L has significant resources and these resources will be called upon as needed to support this IPA project. S&L has served the electric power industry since 1891. During this time, we have developed, designed, managed procurement and conducted construction management for numerous power plants of all types. The facilities we have worked on include fossil-fueled (i.e., oil, gas, coal, etc.), hydro, waste, nuclear, and solar-powered plants. For many plants and clients, we have conducted numerous site selection studies, technology assessments, managed procurement, developed cost estimates, performed full design, and managed construction for successfully operating units. S&L's main office is in Chicago with about 2600 employees in all offices. In addition to out headquarters in Chicago, S&L's global resources include several United States-based regional offices, as well as affiliated joint venture offices in Baroda, India; and Edmonton, Canada. Due to the page limitations as identified in the RFQ, we have attached summary level slides illustrating, S&L's significant power plant experience, on an overall historical level and recent/current experience, including the on-going nuclear design for South Texas Project Nuclear Operation Co. at 1350 MW, scheduled for commercial operation in 2016. Detail backup information for these summary slides are available upon request.

Please note that three of the people included this proposal are participants in the U.S. Department of Energy's Solar Vision study, which has been under way since the spring this year. Goals of the Solar Vision study are to evaluate the technical, economic, and environmental feasibility of meeting between 10% to 20% of U.S. electricity demand from solar energy technologies by 2030, and to identify technology research, development, demonstration, deployment, and policy options that might be employed to help achieve this vision. The Solar Vision study includes central and distributed photovoltaic, concentrating solar, and solar water heating/cooling technologies and is scheduled for publication in early 2010. Solar Vision committee members from S&L are Bob Charles (concentrating solar subcommittee), Bob O'Hara (subcommittee on grid integration of solar), Ken Davis (committee for financing the supply chain and financing solar projects), and Patrick Geenen (solar photovoltaic subcommittee). Messrs. Charles, O'Hara, and Davis are in leadership roles on their respective committees. Messrs. Charles and Davis are members of

S&L's project team that authored a widely-cited study of concentrating solar power in 2003.[1] Mr. Charles leads S&L's consulting practice in solar power for generation of electricity.

We have also attached a list of recent B&W engineering studies for conversion to natural gas.

VI. Study Costs

Our proposed firm price study cost for the above proposed scope is presented as separate task awards and a combined five task award.

- Separate task awards, each task includes three trips as described in Section IV above:
  - Task 1 firm price: $88,000
  - Task 2 firm price: $34,000
  - Task 3 firm price: $34,000
  - Task 4 firm price: $39,000
  - Task 5 firm price: $39,000

- Combined Five Task Award, three trips included as described in Section IV above:
  - Awarded of all five tasks firm price: $182,000

We will invoice 30% of the firm price after the first meeting (kick-off meeting), second 30% after the second meeting to review conceptual designs, 20% after the third meeting (assuming that the meeting occurs one week after the draft report issue) and the remaining 20% after issue of the final report (assuming IPA comments are received within two weeks after the draft report issue). This invoicing applies to separate task awards and the combined five task award.

Terms and Conditions

We will perform the above scope in accordance with the terms set forth in the Services Agreement dated March 31, 2005 between Intermountain Power Agency and S&L, revised to include S&L's current rates, attached for reference.

To summarize, the S&L and B&W team is uniquely qualified to execute this project when you consider the following:

* S&L has significant and recent experience with the design and operation of ALL of the technologies being considered and has performed several studies similar to this for others

* B&W is in a unique position to review the modifications required to the boiler being the boiler OEM

* S&L has a strong knowledge of the IPP site from our work on the conceptual design of Unit 3. While that effort was focused on coal based generation we did learn allot about the site and did have the opportunity to demonstrate the expertise and creativity that we use when approaching projects just like this. We have designed our own in-house tools to perform this work in a very cost effective manner.

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[1] "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts", Report NREL/SR-550-34440 (October 2003), available at http://www.nrel.gov/docs/fy04osti/34440.pdf.

* S&L has demonstrated a strong knowledge of gas fired projects to LADWP over the three years where S&L was LADWP's "gas plant engineer" where we provided almost twenty man-years of work.

* S&L will be using some of the people already known to LADWP and IPP personnel for this work.

It was clear in your request for proposal that you were looking for a very brief and concise reply. I trust that we have accomplished that. I am concerned, however, that we failed to demonstrate just how much expertise we have for this kind of work while trying to be concise. If you have any questions about our offer please call and I would be glad to arrange a meeting where we could discuss our approach/expertise in more detail.

Otherwise, I look forward to the prospect of working with you on this most important project.

Yours very truly,

Jack Daly/B. H. Yee

Jack M. Daly
Project Director

JMD:BY:cl
Enclosures
Copies:
B. Yee
File No. 2.03
IPA-11032009.doc

Sargent & Lundy LLC
Electric Power Experience

188 clients	884 units	~125,000MW
Coal-fired	543 units	60,982 MW
Gas-fired	271 units	30,875 MW
Oil-fired	32 units	5,058 MW
Nuclear	30 units	24,926 MW
Other	8 units	254 MW

Sargent & Lundy LLC

Sargent & Lundy LLC
Type of Plant Technology Experience

Type of Plant	Recent Experience
	Units
Nuclear Plants	
New Generation	**30**
Permitting & Licensing	**24**
Combined Cycle Plants	**28**
Simple Cycle Plants	**17**
Repowering	**18**
Solar Experience	**25**
	(design projects)

Sargent & Lundy LLC

Sargent & Lundy
Air Quality Control Experience

	Recent Experience (Since 2000)	
Multi Pollutant Studies	>30 Utilities	
	Units	MW
FGD Systems		
Wet	43	22,000
Dry (fabric filters)	24	12,000
NOx Controls		
LNB Systems	40	8,000
SCR Systems	54	25,000
SNCR Systems	17	4,300
Particulate Control		
Fabric Filters	39	10,000
ESPs	27	7,800
Mercury Controls (ACI)	72	21,500

Sargent & Lundy LLC

Engineering Studies for Conversion to Natural Gas

Contract Number	Customer	Plant and Unit or City, State	MWe	Boiler OEM	Scope of Supply	Start-Up Year
591-0441	Houston Lighting & Power	P.H. Robinson 1, 4	1227	B&W	Fuel switching to natural gas	1981
591-0777	Mirant Canal LLC	Canal 2	600	B&W	Fuel switching to natural gas	
591-0773	Marmac Engineering				Fuel switching to natural gas	
591-0739	Western Farmers Electric Cooperative	Hugo 1	450	B&W	Fuel switching to natural gas	
591-0735	Mirant Canal LLC	Canal Station 1	543	B&W	Fuel switching to natural gas	
591-0728	Unidentified Customer #1	124 & 125	272	B&W	Fuel switching to natural gas	
591-0727	Unidentified Customer #1	155 & 156	450	B&W	Fuel switching to natural gas	
591-0726	Unidentified Customer #1	153 & 154		B&W	Fuel switching to natural gas	
591-0722	Associated Electric Cooperative, Inc.	Thomas Hill 1-3	345	B&W	Fuel switching to natural gas	
591-0717	Unidentified Customer #4	427 & 429	1150	B&W	Fuel switching to natural gas	
591-0705	Jacksonville Electric Authority	Northside 1	250	B&W	Fuel switching to natural gas	
591-0703	Southern Indiana Gas & Electric	Warrick 4	425	B&W	Fuel switching to natural gas	
591-0663	Consolidated Edison Company of New York	Arthur Kill, Hudson River 2	515	B&W	Fuel switching to natural gas	
591-0652	Public Service Electric & Gas Company	Burlington 7	185	B&W	Fuel switching to natural gas	
591-0641	Dominion Energy Brayton Point LLC	Brayton Point 3	643	B&W	Fuel switching to natural gas	
591-0625	RRI Energy, Inc.	Elrama 1-4	232	B&W	Fuel switching to natural gas	
591-0579	Conectiv Atlantic City Electric Company	Deepwater 8	79	B&W	Fuel switching to natural gas	
591-0569	Constellation Power Source Generation, Inc.	Herbert A. Wagner 1	125	B&W	Fuel switching to natural gas	
591-0563	Dominion Energy	South Street 1 & 2	55	B&W	Fuel switching to natural gas	
591-0530	Exelon Generation Company LLC	New Boston 1 & 2	770	B&W	Fuel switching to natural gas	
591-0453	Jacksonville Electric Authority	Northside 1	250	B&W	Fuel switching to natural gas	

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Engineering Studies for Conversion to Natural Gas

Contract Number	Customer	Plant and Unit or City, State	MWe	Boiler OEM	Scope of Supply	Start-Up Year
591-0449	Pacific Gas & Electric Company	Martinez	25	B&W	Fuel switching to natural gas	
591-0429	Public Service Electric & Gas Company	Linden 11	144	B&W	Fuel switching to natural gas	
591-0418	Unidentified Customer #4		55		Fuel switching to natural gas	
591-0386	Hidroelectrica Espanola, SA	Castellon	540	B&W	Fuel switching to natural gas	
591-0355	Conectiv Atlantic City Electric Company	Deepwater 2	59	B&W	Fuel switching to natural gas	
591-0147	Arizona Public Service Company	Apache 1	75	B&W	Fuel switching to natural gas	
591-0090	Unidentified Customer #4	409 & 410	90	B&W	Fuel switching to natural gas	
591-0077	Cia Electrica De Langreo	Central Da Lada	155	B&W	Fuel switching to natural gas	
591-0010	Northern Indiana Public Service Company	D.H. Mitchell	120	B&W	Fuel switching to natural gas	

Since 1867, The Babcock & Wilcox Company has been a world leader in designing, manufacturing, installing, and servicing utility, industrial, marine and Independent Power Producer steam generating systems. While others may use the "Babcock" name, we are the original. Insist on us by name.

Babcock & Wilcox Power Generation Group, Inc.

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- Outside North America, call: (330) 753-4511
- Fax Worldwide: (330) 860-1886 or (330) 860-1909

For Boiler Replacement Parts:
- Within U.S.A. 24 hours a day, call: 1-800-354-4400
- Outside U.S.A., call: (330) 860-1200
- Fax Worldwide: (330) 860-9350

Website information, communication or e-business: www.babcock.com
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